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Control of Emissions from Lurgi Coal Gasification Plants

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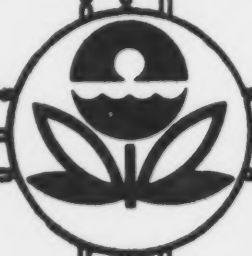
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EPA-450/2-78-012
March 1978
(OAQPS No. 1.2-093)

PB 279 012

GUIDELINE SERIES

**CONTROL OF EMISSIONS
FROM LURGI COAL
GASIFICATION PLANTS**



U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

March 1978

OAQPS GUIDELINE SERIES

The guideline series of reports is being issued by the Office of Air Quality Planning and Standards (OAQPS) to provide information to state and local air pollution control agencies; for example, to provide guidance on the acquisition and processing of air quality data and on the planning and analysis requisite for the maintenance of air quality. Reports published in this series will be available as supplies permit - from the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, or, for a nominal fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

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1. SUMMARY

The purpose of this document is to provide information on Lurgi coal gasification plants, their emissions, control technologies which can be used to control emissions, and the environmental and economic impacts of applying these control technologies. Fuel conversion plants are included in the definition of major emitting sources under section 169 of the Clean Air Act. This means that any coal gasification plant must obtain a permit before construction begins. The plant must apply best available control technology (BACT) before a permit is granted. EPA does not plan to develop a new source performance standard for Lurgi coal gasification plants. This document is being issued, therefore, to enable State, local, and Regional EPA enforcement personnel to determine BACT for Lurgi coal gasification plants on a case-by-case basis. To obtain copies of this document, write to the Environmental Protection Agency Library, MD-35, Research Triangle Park, North Carolina 27711.

Two alternative emission control systems for the reduction of hydrocarbon and sulfur compound emissions from coal gasification plants are considered in this document. These alternatives were developed using a "transfer-of-technology" approach since no gasification plants are in operation which are representative of the gasification plants which will be built in the U. S. Estimates of the emissions from these alternative emission control systems were based on: engineering design data on gasification plants to be built in the U. S.; data demonstrating the effectiveness of emission controls on waste gas streams similar to coal

gasification plant waste gas streams, vendors' guarantees on the performance of emission control systems, and contractor studies on coal gasification technology.

Alternative emission control system I uses Claus and Stretford sulfur recovery plants for controlling sulfur compound emissions and incineration to control nonmethane hydrocarbons emissions from Lurgi coal gasification plants. Alternative emission control system II consists of two options, each achieving essentially the same degree of emission control. Option I uses a single Stretford plant to control sulfur compound emissions and incineration to control nonmethane hydrocarbon emissions. Option 2 uses a Stretford and a Claus plant for controlling sulfur compound emissions. Alternative emission control system I achieves 91 to 95 percent control of sulfur compound emissions while alternative emission control system II achieves 96 to 98 percent control of sulfur compound emissions. There is no difference in the degree of nonmethane hydrocarbon achieved by these two alternative emission control systems.

2. INTRODUCTION

This control technique document for Lurgi coal gasification plants has been prepared following a detailed investigation of air pollution control methods available to the affected industry and their costs to the industry. This document summarizes the information obtained from such a study of coal gasification plants. Its purpose is to explain in detail the background to those who may be familiar with the many technical aspects of the industry.

2.1 REASONS FOR ISSUING GUIDELINES

2.1.1 Significance of Source

Coal gasification plants are stationary sources of air pollution which may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare and are considered as high priority for control. The coal gasification industry is also an emerging industry. Emerging industries present a unique opportunity to integrate air pollution control into the early development and design of new processes, rather than "adding-on" control as an after-thought. Regulations for the control of emerging industries will encourage development of environmentally acceptable industries and will ensure that emerging industries do not create new air pollution problems.

Growth projections indicate that by 1981 five coal gasification plants will be in operation producing SNG for the domestic natural gas industry. Few State or local regulations exist limiting emissions from

these plants. If uncontrolled, these five projected coal gasification plants would emit some 750,000 tons per year of particulate emissions; some 550,000 tons per year of sulfur compounds (two-thirds of which would be hydrogen sulfide); some 80,000 tons per year of nitrogen oxides (NO_x) emissions; and some 35,000 tons per year of carbon monoxide emissions.

Uncontrolled emissions of hydrogen sulfide from a single plant could lead to severe local odor problems and result in injury to sensitive crops. Uncontrolled emissions of sulfur dioxide and nonmethane hydrocarbons from a single plant would also lead to ambient air concentrations of these pollutants exceeding the national ambient air quality standards (NAAQS).

Although a few State or local regulations exist limiting emissions from coal gasification plants, plants constructed in the United States must meet State regulations developed for attainment of the national ambient air quality standards for particulate matter, sulfur oxides, nitrogen oxides, hydrocarbons, oxidants, and carbon monoxide and regulations developed to prevent significant air quality deterioration (PSD) (42 FR 57479, and section 127 of the Clean Air Act Amendments of 1977). In areas where the NAAQS have not been met, they must also meet the new source review and emission offset regulations (41 FR 55525, as amended by section 129 of the Clean Air Act Amendments of 1977).

For most sources, the degree of emission control required to comply with PSD regulations varies depending on the classification of the area in which the source is located. For many sources, however, including coal gasification plants, "best available control technology" (BACT) is required in all situations. Assuming that the plans recently put forth by the domestic natural gas industry proposing construction of commercial

coal gasification plants incorporate the degree of control necessary to comply with applicable NSPS, MAAOS, and BACT provisions of the PSD regulations, the first five coal gasification plants projected for construction in the United States by the domestic natural gas industry will emit some 15,000 tons per year of particulate matter; some 110,000 tons per year of sulfur compounds (essentially all of which would be SO_2); some 50,000 tons per year of NO_x ; and some 3,000 tons per year each of nonmethane hydrocarbons and carbon monoxide. Coal gasification plants, therefore, would be significant emission sources of particulate matter, sulfur compounds, NO_x , nonmethane hydrocarbons, and carbon monoxide, all of which contribute to the endangerment of public health or welfare.¹

2.1.2 Consideration of Alternative Actions

Currently, no commercial coal gasification plants are either operating or under construction in the United States. The domestic natural gas industry, however, is proposing to start construction of these plants to produce SNG by early 1978. Since the coal gasification industry does not presently exist in the United States, alternatives to immediate proposal of standards of performance, such as no action/delayed action or issuance of guidelines, merit consideration. Although a few small coal gasification plants are in other countries, much of the emission control technology that will be employed to reduce emissions has not been applied to coal gasification plants. Furthermore, a number of different coal gasification processes are currently under development. Since the picture will be much clearer in a few years after a few coal gasification plants have been built and accumulated operational experience, both with the coal gasification process and the emission control technology, a case can be made for either no action or delayed action.

While much of the emission control technology necessary to control emissions from coal gasification plants has not yet been applied to these plants, this technology has been well demonstrated in similar industrial applications. Much of this technology will be applied to coal gasification plants to comply with the NAAQS and the PSD regulations. The major area of uncertainty, therefore, is not so much will this technology work, but how well will it work. As a result, selection of numerical emission limits requires inclusion of some margin for error; numerical emission limits, however, can be selected.

Although a number of different coal gasification processes are under development, this is not likely to delay emergence of a coal gasification industry in the United States in the near future. At this point the coal gasification process that will be used in these first plants has been selected. Taking no action or delaying action will not change this selection. It is possible to limit application of State and local regulations to the coal gasification process which will be employed in these first plants and tailor emission limitations to this process. While this will unavoidably establish a "benchmark" for all processes under development to achieve, it provides the flexibility of extending these emission limitations to other processes, or of developing emission limitations for other coal gasification processes as they are developed, whichever is appropriate.

As mentioned above, construction of the first commercial coal gasification plants to produce synthetic natural gas (SNG) could start by early 1978. Thus, there is little doubt that a domestic coal gasification industry will definitely emerge, take shape and expand within the United States over the next decade. In fact, the overall energy program recently put

forth by the Administration will actively encourage and support the growth of such an industry. At the same time, however, protection of the environment is one of the ten key principles underlying this program.

Consequently, taking no action or delaying action is not considered a viable alternative. The real question is what type of action: issue guidelines, or propose standards of performance. Guidelines would serve as the basis for development of emission limitations under the PSD regulations. This would provide a technical definition of BACT for Lurgi coal gasification plants to be used in conjunction with the PSD regulations.

The degree of emission control necessary to comply with the NAAQS will vary to some extent depending on meteorology, plant size and geographical location. In addition, the determination of BACT under the PSD regulations would continue to be done on a case-by-case basis. This approach would probably achieve the same end result, in terms of emission control, as standards of performance.

The plans for the coal gasification plants now under consideration by the domestic natural gas industry have been reviewed, and it appears that these plants will incorporate air pollution control consistent with the data and information gathered by EPA. Since only a few commercial coal gasification plants are likely to be built in the foreseeable future, and it is anticipated that these plants will be adequately controlled, EPA will issue control guidelines. The guideline document can be used by the EPA Regional Offices and States in reviewing future plans for these plants and will also assist State and local air pollution control agencies in formulating regulations for the control of pollutant emissions from these plants.

2.2 BACKGROUND INFORMATION

2.2.1 Commercially Available Processes²

Atmospheric-pressure gasifiers were constructed and used in Europe as early as the 1840's. By the early 1900's there were about 150 companies in Europe and the United States building gasification plants. At that time gasifiers fed gas to gas engines, heating furnaces, and kilns. In 1921 there were about 11,000 commercial gasifiers in the United States consuming more than 15 million tons of coal annually.

During the 1920's competition from petroleum and natural gas products resulted in a rapid decline in coal gasification. By 1948 there were still 2000 gasifiers in use; however, the number has since diminished so that no significant number of commercial gasifiers are presently used in the United States.

Commercial coal gasification processes in use today outside the United States include the Lurgi, Koppers-Totzek, and Winkler processes, all for the manufacture of "synthesis" and fuel gases. Practically all of the first-generation coal gasification projects--those being engineered in commercial sizes today--are based on use of the Lurgi process, which is discussed in subsequent sections. Because of the current energy situation, coupled with the realization that 20- to 30-year-old technology is being used in coal gasification projects planned to meet the crisis, many new coal gasification processes are now being developed. Most of these, however, are only lab or bench-scale processes. None are expected to be commercialized until the early to mid-1980's.

Three types of coal gasification plants have been proposed--low-Btu gasifiers for industrial and utility boiler fuels; intermediate-Btu gasifiers producing "synthesis" gas as feedstock for manufacture of liquid fuels, methanol, ammonia and possibly other valuable chemicals; and high-Btu or

substitute natural gas (SNG) to supplant declining natural gas supplies. For the low-Btu case, no commercial-sized plants exist; however, pilot-scale and demonstration plants are planned. One low-Btu demonstration plant is already in operation in Germany.³ Intermediate-Btu gas projects in the United States are also under consideration at this time, with no announced commercial plants.⁴

High-Btu coal gasification is well advanced with at least 22 plants under study and initial construction of five plants projected by 1981. With high-Btu gasification nearest commercial production and process and emission control schemes unclear for the other cases, initial development of control guidelines will be directed toward high-Btu gasification.

2.2.2 Projections of Coal Gasification Fuel Production

Future plants producing high-Btu gas from coal in the United States have been estimated by several organizations in the recent past, with the results shown in Table 3-1.⁵ Using the more recent projections of the Bureau of Mines, only one high-Btu coal gasification plant is expected on stream by 1980. However, the projected increases through 2000 show rapid growth--a 620 percent increase in production in 20 years. The 5500-6200 trillion Btu's projected in Table 3.1 for the year 2000 correspond to 60-68 plants producing 250 billion Btu's (~270 million cubic feet) of SNG per day. [The typical planned SNG plant is sized at 250 billion Btu per day gas output.]

The future for low-Btu coal gasification plants is less certain. Only one estimate has been made (Table 3.2) and that only for retrofitting existing boilers with low-Btu gasifiers.⁶ If low-Btu gas is shown to be an adequate substitute for industrial purposes and if "town gas" for residential purposes becomes economically competitive once again, the estimates in Table 3.2 for

low-Btu gas may be low. The rate of projected use of low-Btu gas is sensitive to regulatory actions because of competition from alternate power generation schemes. High-Btu gas is probably less sensitive to regulatory activities (other than simple regulation of price structure) because there are few alternatives to natural gas as both a raw material and fuel.

TABLE 2.1 SURVEY OF ESTIMATES OF FUTURE SUPPLY
OF PIPELINE QUALITY (HIGH BTU) GAS
PRODUCED FROM COAL IN THE UNITED
STATES (Trillions of Btu)⁵

Source	Year				
	1980	1985	1990	1995	2000
FTC ^(a)	300	1100	3100	800	--
USD ^(b)	700	2000	--	--	5500
USEM ^(c)	100	1300	3000	4000	6200

^aFederal Power Commission

^bU.S. Dept. of Interior

^cU.S. Bureau of Mines

TABLE 2.2 ESTIMATE OF FUTURE SUPPLY OF LOW-ENERGY
(LOW BTU) GAS PRODUCED FROM COAL IN THE
UNITED STATES (Trillions of Btu)⁶

Source	Year				
	1980	1985	1990	1995	2000
EPA	0	480	--	--	3900

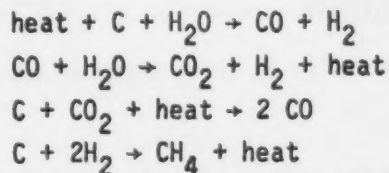
2.3 REFERENCES

1. Air Quality Criteria for Particulate Matter (AP-49), Sulfur Oxides (AP-50), Carbon Monoxide (AP-62), Photochemical Oxidants (AP-63), Hydrocarbons (AP-64), and Nitrogen Oxides (AP-84), U.S. Department of Health, Education and Welfare, Public Health Service, National Air Pollution Control Administration.
2. Kim, B.C. et al., "Final Report - Development of Information for Standards of Performance for the Fossil Fuel Conversion Industry," EPA Contract No. 68-02-0611, Task 7, Battelle-Columbus Laboratories, Oct. 11, 1974, pp. A-9.
3. Krieb, K.H., "Combined Gas and Steam Turbine Process with Lurgi Coal Pressure Gasification" presented at IGT Symposium on Clean Fuels from Coal, Chicago, Illinois, Sept. 10-14, 1973.
4. Synthetic Fuels, Vol. 13, No. 1, Cameron Engineers, Inc., March, 1976, pp. B-20, B-27.
5. Reference 1, pp. A-10.
6. Reference 5.

3. PROCESS DESCRIPTION

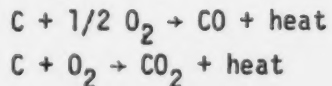
3.1 GENERAL

In simple terms coal gasification is the combination of coal and water to form carbon monoxide, hydrogen and some methane. Both heat and elevated temperatures are required to promote the gasification reactions, which are many and varied. The major gasification reactions are:



The predominant reaction is the first - the combination of carbon and water to form carbon monoxide and hydrogen. This reaction requires heat, which indicates that coal gasification is a net consumer of heat. Key requirements for coal gasification are therefore coal (carbon), water (steam), and heat.

The most common source of heat for promoting the gasification reactions is combustion or partial combustion of coal in the gasifier. This approach is favored because only air or oxygen must be added to the gasifier to initiate the gasification process. Thus to the major gasification reactions, two more may be added:



Other important gasifier reactions involve conversion of sulfur in coal to hydrogen sulfide (H_2S) and carbonyl sulfide (COS). These potential pollutants and their fate throughout subsequent processing steps will be discussed later in this chapter.

All coal gasification schemes produce some by-products which typically include phenols, naphtha, coal tars, light oils, and sulfur, the amount of each depending upon the type of gasification process and plant size.

3.2 LURGI COAL GASIFICATION PROCESS¹

First generation coal gasification processes are based on the Lurgi coal gasifier shown in Figure 3.1. In the Lurgi gasifier, gasification takes place in a countercurrent moving bed of coal at 300-400 psig and 1000-1400°F. A cyclic operation using a pressurized lock hopper is used to feed coal.

The gasifier has a water jacket to protect the vessel and provide steam for gasification. Other features include blades to mechanically overcome caking, a moving grate on the bottom to remove the dry ash, and a mechanism to introduce steam and air or oxygen uniformly over the gasifier.

In general there are three process zones in the gasifier. The first zone devolatilizes the coal. As the coal drops down, it is met with hot synthesis gas ascending from the bottom, which liberates the volatile hydrocarbons from the coal. As the coal drops lower into the second zone, gasification occurs by the reaction of carbon with steam. Finally as the coal approaches the grate, carbon is burned to produce the heat required for the gasification process. The chemical reactions associated with these zones are listed in Table 3.1.

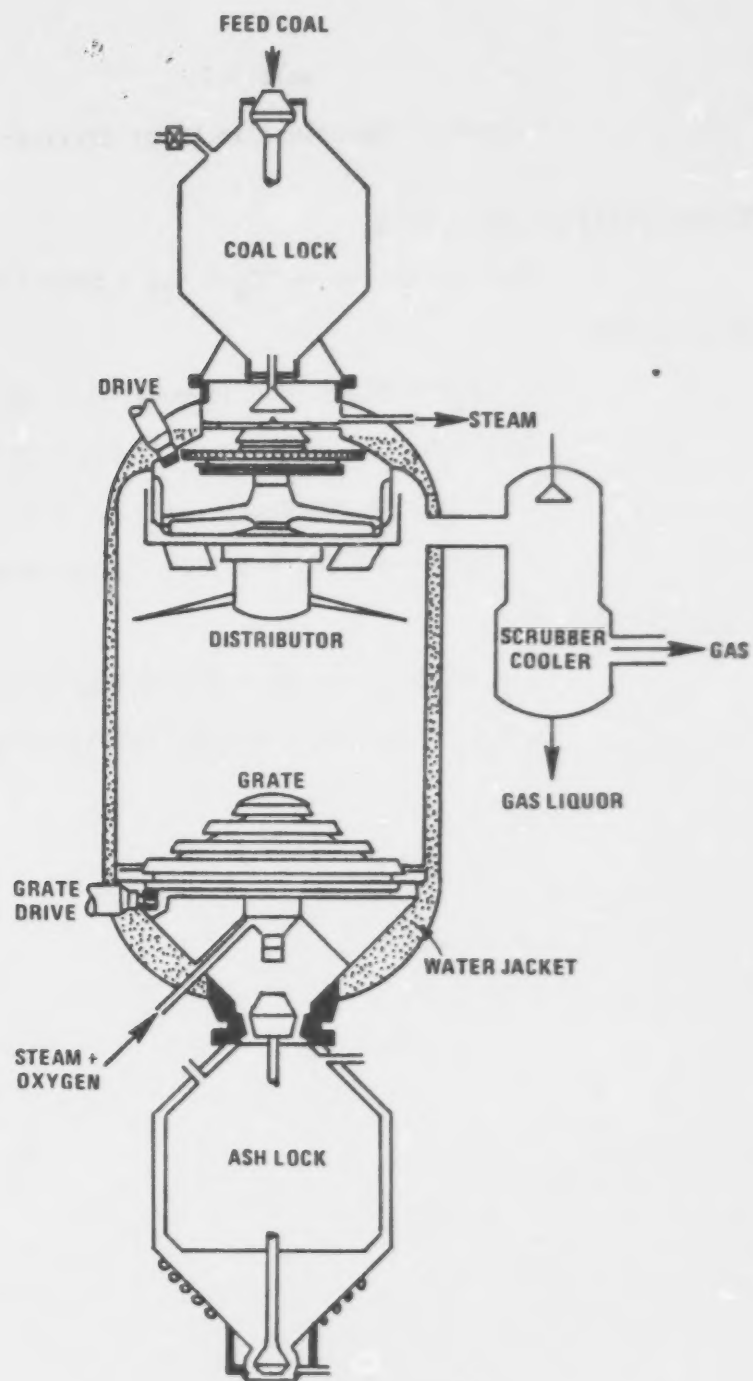
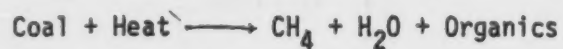


Figure 3.1 Lurgi gasifier.

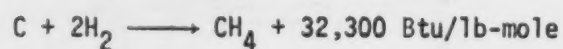
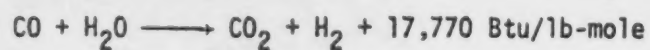
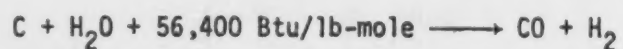
Table 3.1

Chemical Reactions in Lurgi Gasifier

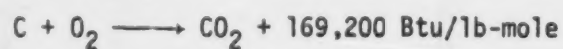
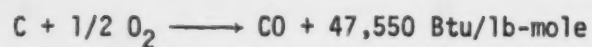
Devolatilization and Drying



Gasification



Partial Combustion



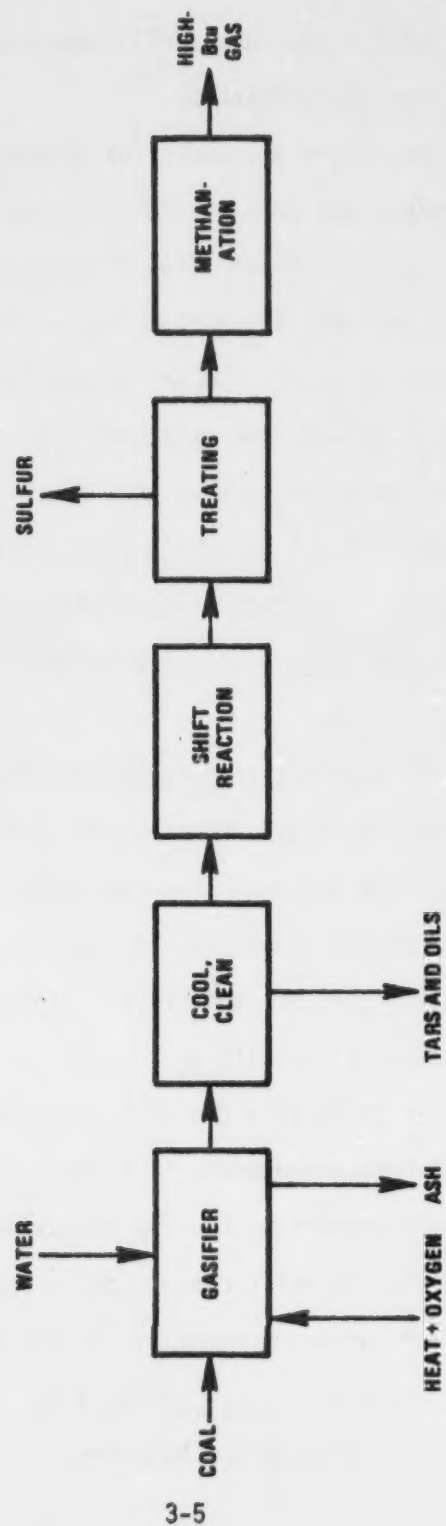


Figure 3.2. High-Btu Gas Production

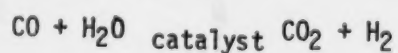
Top and middle zone temperatures are generally between 1100 and 1400°F, where devolatilization and gasification take place. Depending on the type of coal, the gas leaves the bed between 700 and 1100°F. Process gas leaving the Lurgi gasifier contains coal dust, oil, naphtha, phenol, ammonia, tar oil, ash, char and other constituents.

Before the raw gas can be processed for conversion into high-Btu gas, oils, tars, and entrained ash or chars must be removed. Hence, a scrubbing cooler as shown in Figure 3.1 is an integral part of the Lurgi gasifier. Water is used to cool the gas coming from the gasifier and to remove oils, tars, and entrained ash or char. The gas liquor from this scrubber cooler is further processed to recover the oils and tars.

Several high-Btu gas projects have been announced and are in various degrees of engineering status.² Figure 3.2 illustrates a typical Lurgi high-Btu gasification process. The major coal gasification steps include coal gasification, oil and tar removal, shift conversion, acid gas treating and methanation.

In addition to the gasification process itself, other major components include a large, 250-500 megawatt, power boiler and steam superheater to provide steam for the gasification process; an oxygen plant which supplies oxygen to the gasifier; coal receiving, handling, storage and preparation facilities; by-product ammonia, oil, and tar recovery and storage facilities, water treating facilities, and ash disposal facilities.

The Lurgi gasifier produces a gas rich in carbon monoxide and carbon dioxide, while the desired end product is methane, CH₄. Hydrogen is supplied from water in the shift conversion usually following preliminary tar, oil, and particulate removal. In shift conversion, one mole of water catalytically reacts with one mole of carbon monoxide by the reaction



to form additional carbon dioxide and hydrogen.

Carbon dioxide and sulfur compounds must be removed from the process to meet pipeline gas specifications, since CO_2 lowers the heating value of the product gas and sulfur compounds present corrosion problems in the pipeline. Also, any sulfur present in the methanation stage will poison methanation catalysts; thus, all sulfur must be removed prior to methanation.

Following the shift conversion, a gas purification process, also called acid gas sweetening, removes most of the CO_2 and essentially all the sulfur compounds. For Lurgi coal gasification plants currently planned, the Rectisol process is used to remove CO_2 and sulfur compounds. The Rectisol process is a physical solvent process using cold methanol as the absorbing medium. No chemical reactions occur, only the physical absorption of CO_2 and sulfur compounds under high pressure in the methanol solution. Regeneration of the methanol solution by lowering the pressure and application of heat liberates the absorbed CO_2 and sulfur compounds.

Following acid gas sweetening, the purified gas is methanated. Methanation consists of reacting the hydrogen in the purified gas with carbon monoxide and residual CO_2 at elevated temperatures in the presence of a catalyst to form methane. The methanated gas is then treated for further CO_2 removal, if necessary, dried and compressed for injection into the pipeline. Product gas has a typical heating value of 950-970 Btu per standard cubic foot and consists of roughly 96-97 percent methane, 0.5-2 percent CO_2 , 1 percent inert gas (nitrogen + argon) and 1 percent H_2 plus CO.

3.3 EMISSIONS FROM COAL GASIFICATION

Although emissions from coal gasification plants may be classified into general source categories, the quantity and composition of emitted gas streams can vary significantly, depending on the type of feedstock coal, operating conditions in the process equipment, and the process equipment itself.

Generally, emission sources from coal gasification plants are (1) raw materials handling and pretreatment, (2) vent gases from start-up, shutdown, and routine charging of the gasifiers, (3) by-product recovery and storage, (4) waste water treatment, (5) acid gas cleaning, (6) catalyst regeneration, and (7) power generation (see Figure 3.3). The following discussion of emissions is based on a typical planned Lurgi coal gasification installation-- 250 billion Btu per day product gas, with 1.0 lb sulfur/10⁶ Btu feedstock coal.

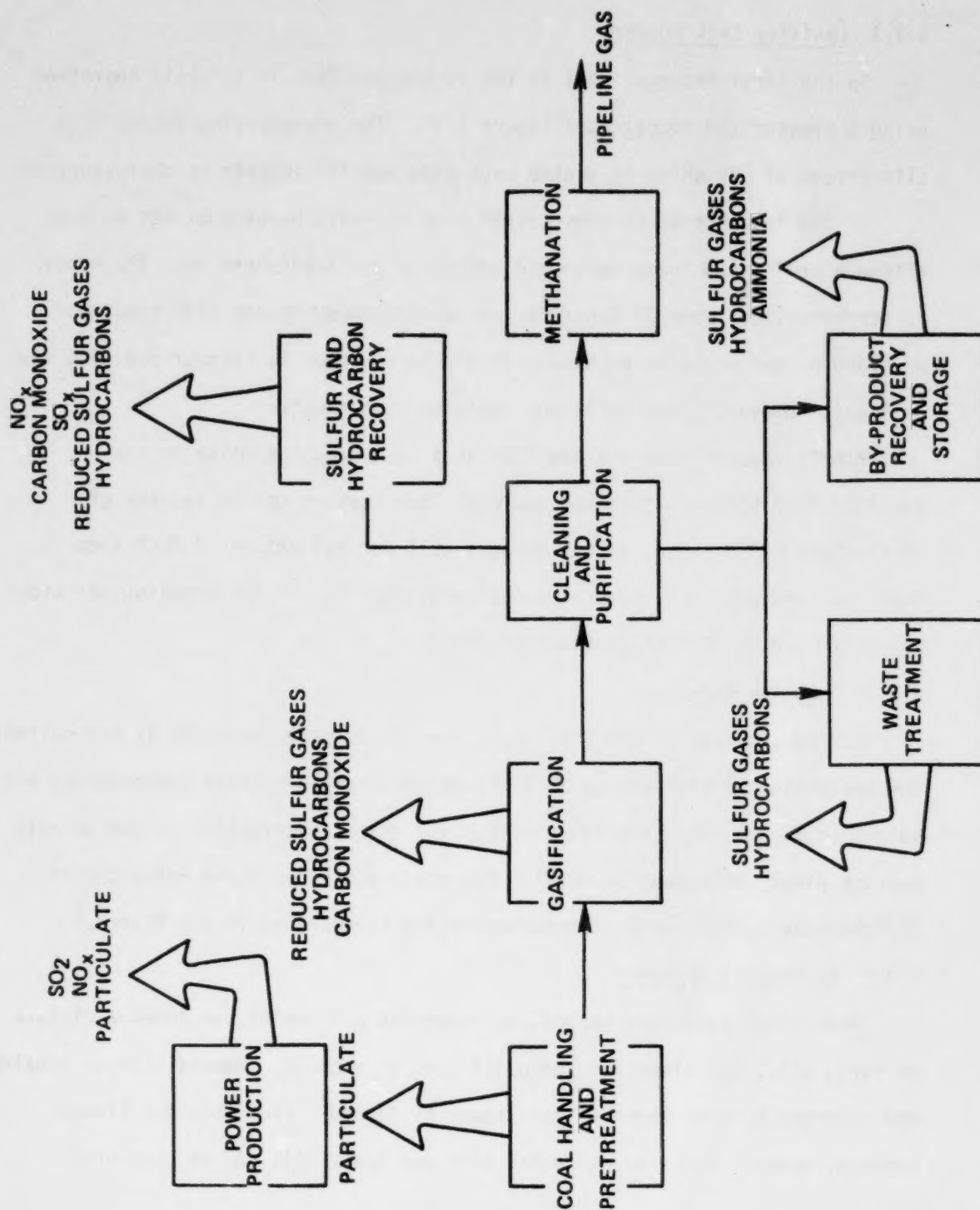
3.3.1 Coal Storage and Pretreatment

Coal storage and pretreatment is the primary emission source in raw materials handling. Current schemes call for coal to be delivered, crushed, stored, and blended before being conveyed to the gasifier. Since the Lurgi gasifier accepts only a limited size range (1 3/4" x 3/16") of coal, preliminary screening of gasifier feed is also required. Depending upon the particle size and surface moisture of the coal, emissions from all coal handling and storage operations may be significant.

No definitive data are available for coal storage emissions; however, estimates for coal handling and coal gasifier charging stack emissions are roughly 410 tons/year uncontrolled particulate and 4.3 tons/year particulate controlled by baghouses and wet cyclones.

Under Federal standards of performance promulgated in the January 18, 1976, Federal Register, all coal handling operations are required to control particulate emissions to less than 20 percent opacity. Exempted from this regulation are emissions from coal storage piles and from thermal drying of lignite and subbituminous coals. Lurgi gasification schemes do not require thermally dried coal.

Figure 3.3. EMISSIONS AND EMISSION SOURCES IN HIGH-BTU COAL GASIFICATION



3.3.2 Gasifier Lock Hopper

In the Lurgi process, coal is fed to the gasifier in a cyclic operation using a pressurized hopper (see Figure 3.1). The pressurizing medium is a slip stream of gas which is vented each time the lock hopper is depressurized.

If the lock hopper is pressurized with an inert by-product gas such as nitrogen or CO_2 and these gases are vented to the atmosphere when the hopper is depressurized, some 25 tons/year of sulfur compounds and 4000 tons/year of hydrocarbons would be emitted. If the lock hopper is pressurized with raw coal gas, however, these emissions would be much greater.

Ash is removed from the gasifier in a lock hopper similar to the gasifier feed hopper. Both ash and coal lock hoppers may be sources of particulate emissions. Current designs call for collection of dust from both coal and ash lock hoppers on the Lurgi gasifier.³ Ash handling emissions are estimated at 27 tons/year uncontrolled.

3.3.3 Start-up Gases

During start-up of the gasifiers, raw gas is produced which is not suitable for production of high-Btu gas. Although these gases contain hydrocarbons and sulfur compounds, they are intermittent and their contribution to the overall average plant emissions is small. One study estimates these emissions at 25 tons/year sulfur, with hydrocarbons being incinerated in the flares.⁴

3.3.4 By-product Recovery

When Lurgi gases are cooled, and quenched with water, an aqueous mixture of tars, oils, and dissolved compounds such as phenols, ammonia, carbon dioxide and hydrogen sulfide known as gas liquor is formed. From this gas liquor naphtha, phenol, ammonia, and other tars and heavy oils may be recovered.

During separation and recovery of these by-product oils and tars, gases are released which contain hydrogen sulfide and carbon dioxide.

3.3.5 Waste Water Treatment

Acid gases are also released from sour water stripping of the waste water remaining following recovery of phenol from the gas liquor. These acid gases, primarily H_2S and CO_2 , are routed to the sulfur recovery plant.

3.3.6 Acid Gas Removal and Sulfur Recovery

In the gasification of coal for making pipeline quality gas, removal of all sulfur species is required to prevent poisoning of the methanation catalyst and avoid subsequent pipeline corrosion. In addition, carbon dioxide must be removed to achieve the high heating value of pipeline gas. Numerous gas sweetening schemes are available to remove H_2S and CO_2 .

There are many possible sulfur removal schemes for coal gasification plants. Based on use of the Rectisol process, and combining of the acid gases from sour water stripping with the Rectisol vent gases, the uncontrolled emissions are estimated at:

Non-methane hydrocarbons	25,600 tons/year
Carbon monoxide	6,750 tons/year
Hydrogen sulfide	70,000 tons/year
Carbonyl sulfide	2,000 tons/year

Total potential sulfur emissions in these acid gases represent greater than 95 percent of the sulfur input to the gasification process.

3.3.7 Catalyst Regeneration

Periodically methanation catalysts require regeneration to retain their activity. In regeneration hot gases are passed over the catalyst to remove foreign substances from the catalyst surface. Off-gases would include sulfur compounds, trace elements, and the carrier gas. Because of the intermittent

nature of emissions, the overall contribution to total plant emissions is small. Catalyst regeneration emits approximately 70 tons of sulfur dioxide annually.

3.3.8 Steam Generation

To generate steam required for the gasification process, a coal-fired boiler, rated at approximately 3.2 billion Btu/hour is an integral part of the gasification complex.

In most cases a steam superheater, fired with by-product oil and tar, waste hydrocarbons, and supplemental fossil fuel is also present. The superheater capacity will be roughly 320 million Btu/hour. Emissions from these combined units, based on existing new source performance standards, would be 18,700 tons/year SO_2 , 10,900 tons/year NO_x , and 3,100 tons/year particulate. Uncontrolled emissions would be roughly 31,000 tons/year SO_2 , 15,800 tons/year NO_x , and 152,000 tons/year particulates.⁵

Table 3.2 summarizes the expected uncontrolled emissions and emission sources for a typical high-Btu Lurgi gasification plant with 1.0 lb sulfur per million Btu coal feedstock. From this table it is quite apparent that any regulations should be directed toward limiting sulfur and hydrocarbon emissions from the gasifier and subsequent gasification processes, since the steam generation facilities are already subject to standards of performance.

3.4 FACTORS INFLUENCING GASIFIER EMISSIONS

3.4.1 Coal Feedstock

Coal is a heterogeneous substance varying with geographic area, coal seam, and, more importantly, location within the same seam. Thus, a gasification plant processing coal from one particular seam may experience the same magnitude of process instability as a plant processing a mixture of coal seams. Many important coal properties which influence ultimate emissions from

Table 3.2. UNCONTROLLED EMISSIONS FROM 250 x 10⁹ Btu/DAY LURGI GASIFICATION PLANT^a

	Uncontrolled Emission Rate, Tons/Yr				
	Particulate	SO ₂	NO _x	CO	Non-Methane HC
Raw Material					Reduced Sulfur
Storage & Handling:					
Coal Storage					
Coal Handling					
Gasifier Charging	390		No Data Available		
	20				
Gasifier Vent					29
Start-up Flare		9.0			4,000 ^b
By-product Recovery					1,200
Sour Water Stripping					1,800
Ash Handling	27				
Acid Gas Cleaning				6,750	25,600
Catalyst Regeneration		85			72,000
Steam Generation	152,000	31,000	15,800		

^aBased on coal feedstock of 1.0 lb sulfur per 10⁶ Btu.

^bTotal hydrocarbons.

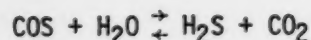
the gasification plant are not normally measured. In short the coal gasification facility has a feedstock that is known to vary widely. Subsequent design of the gas processing facilities must allow for conditions unsteady in comparison to that of chemical plants, refineries, and natural gas plants.

3.4.2 Gasifier Conditions

The formation of the more difficulty controlled pollutants, such as carbonyl sulfide and non-methane hydrocarbons, is a function of gasifier operating conditions. Under conditions in the Lurgi gasifier (1500°F, 30 atm), significant yields of ethylene are obtained. The relationship between carbonyl sulfide formation and gasifier conditions is somewhat unclear due to the limited data available. In the Lurgi raw coal gas, COS is reported as 1.4 to 5.6 percent of the total gasified sulfur.⁶

3.4.3 Water-Gas Shift

In the water-gas shift process, where steam is catalytically reacted with carbon monoxide, some hydrolysis of carbonyl sulfide is expected to take place by the reaction:



One estimate indicates that carbonyl sulfide following the water-gas shift represents about 1.8 percent of the total gasified sulfur. In processing schemes where the water-gas shift follows gas purification, the COS loading on the purification process would be 4.0/1.8 or 2 1/3 times that of the typical Lurgi processing scheme.

3.4.4 Gas Purification

Available gas purification processes are discussed in the following chapter. Only the Rectisol purification process, however, has been used with the Lurgi gasifier. The Rectisol process, using a refrigerated methanol solvent, has the advantage that all the hydrogen sulfide and organic sulfur

are removed from the raw coal gas. Unfortunately, methanol also has an affinity for other organics in the raw gas, including hydrocarbons. Regeneration of the methanol solvent liberates the absorbed sulfur and hydrocarbon compounds.

The methanol solvent in the Rectisol process also removes the carbon dioxide present in the raw coal gas. Since much more carbon dioxide is present than hydrogen sulfide and hydrocarbons, the off-gases from the Rectisol process only contain about 1 to 4 percent hydrogen sulfide. Hence, additional schemes may be used to concentrate the hydrogen sulfide content in the acid gases to simplify subsequent sulfur recovery.

The selection of a gas purification process will depend, in part, upon the process chosen for treating the acid gases for sulfur recovery. Detailed discussion of available processes may be found in the following chapter.

3.5 REFERENCES

1. Shaw, H. and Margee, E.M., "Evaluation of Pollution Control in Fossil Fuel Conversion Processes - Gasification, Section 1, Lurgi Process," EPA Contract No. 68-02-0629, Exxon Research and Engineering Co., July, 1974.
2. Synthetic Fuels, Vol. 13, No. 1, Cameron Engineers, Inc., March, 1976, pp. 13-20 through B-46.
3. Application for Permit and Certificate of Registration for Sources Located Within the State of New Mexico by Western Gasification Company, Nov. 10, 1975, pp. 3.
4. Reference 3.
5. Reference 3, p. 4.
6. "Trials of American Coals in a Lurgi Gasifier at Westfield, Scotland," Research and Development Report No. 105, Energy Research and Development Administration, Washington, D.C. (no date).

4. EMISSION CONTROL TECHNIQUES IN HIGH-BTU COAL GASIFICATION

4.1 DEMONSTRATED TECHNOLOGY

The alternative control systems for coal gasification plants discussed in this guidance document are based on a "transfer-of-technology" approach. Although no commercial coal gasification plants have been constructed in the United States, seven Lurgi coal gasification plants are currently operating in other countries. These plants, however, are generally not representative of those planned for the United States.

The Lurgi coal gasification plants projected for construction in the United States by the domestic natural gas industry will produce SNG and will employ the Lurgi Rectisol process to remove carbon dioxide and hydrogen sulfide from the coal gas. Four of the seven Lurgi coal gasification plants currently operating in other countries produce "town-gas" or a "low-Btu" fuel gas, as opposed to SNG, and use an alkaline scrubbing process to remove hydrogen sulfide from the coal gas. This process, however, does not remove carbon dioxide from the coal gas and, as a result, the characteristics of the waste gas streams discharged from these four plants are quite different from those that will be discharged from the plants constructed in the United States.

The remaining three Lurgi coal gasification plants produce an "ammonia-synthesis" gas. Although these plants employ the Lurgi Rectisol process to purify the coal gas, two of them are less than a tenth the size of the plants

projected for construction in the United States. Either because of their relatively small size, or because they are located in countries where air pollution is not a major concern (i.e. Korea and Pakistan), both of these plants operate uncontrolled.

The remaining Lurgi coal gasification plant is located in South Africa. While this plant is about three-quarters the size of those projected for the United States, it currently operates uncontrolled. A Stretford sulfur recovery plant, however, is presently under construction and will reduce emissions of sulfur compounds by about 90 percent when it is placed in operation.

The Rectisol process is the major emission source in a Lurgi coal gasification plant. The waste gas streams discharged from this process contain about 95 percent of the potential sulfur compound emissions and about 85 percent of the potential non-methane hydrocarbon emissions resulting from the coal gasification process. The characteristics of these waste gas streams, therefore, dictate the emission control technology that can be employed.

The Rectisol process uses a methanol solvent under high pressure (~ 700 psig) and at low temperature ($\sim 50^{\circ}\text{F}$) to remove carbon dioxide and hydrogen sulfide from the raw coal gas by physical absorption. The methanol solvent is regenerated in a two-step process. First, the solvent is passed through a series of pressure reduction stages to release absorbed hydrogen sulfide and carbon dioxide by "flashing"; the solvent is then subjected to a "thermal" regeneration in which the methanol is heated to release additional hydrogen sulfide and carbon dioxide. Based on data and information developed by the domestic natural gas industry, depending on the properties of the coal gasified, the composition of the waste gas stream discharged by the flash regeneration

step will be a "lean" gas stream of about 97-98 percent carbon dioxide, about 1/2 percent hydrocarbons, and about 1/4- 1 1/2 percent hydrocarbon sulfide. The composition of the waste gas stream discharged by the thermal regeneration step, however, will be a "rich" gas stream of about 50-75 percent carbon dioxide, about 5-10 percent hydrocarbons and about 5-40 percent hydrogen sulfide.

Technology for control of the hydrogen sulfide contained in these waste gas streams has been well demonstrated in other industries. The waste gas streams discharged from the coke ovens at several steel mills in other countries frequently contain 1/2-1 percent hydrogen sulfide and these gases are normally controlled by Stretford sulfur recovery plants which remove the hydrogen sulfide and convert it to elemental sulfur.

The primary difference in composition between these coke oven gases and the waste gases discharged from the Rectisol process is the carbon dioxide content. The carbon dioxide content of the gases discharged from coke ovens is about 1-2 percent, whereas that of the "lean" waste gas stream discharged from the Rectisol process, or the combined "lean" and "rich" waste gas streams, is about 96-98 percent. Consultation with vendors of the Stretford process, however, indicates that this process is not sensitive to the carbon dioxide content of the gases treated and will reduce the hydrogen sulfide content of the waste gases discharged from the Rectisol process to 0.01 percent, or 100 ppm.

Technology for control of the hydrogen sulfide contained in the "rich" waste gas stream discharged from thermal regeneration of the methanol solvent in the Rectisol process has been well demonstrated in the oil and natural gas production industry. The waste gas stream discharged from the gas purification facilities at a natural gas plant can contain as little as

15-20 percent hydrogen sulfide and as much as 75-80 percent carbon dioxide. These gases are normally controlled by Claus sulfur recovery plants which remove the hydrogen sulfide and convert it to elemental sulfur. Although Stretford plants could be used to control these gas streams, Claus plants are more economical and are normally used.

The rich waste gas stream discharged from the Rectisol process, however, as noted above, contains about 5-10 percent hydrocarbons. A hydrocarbon concentration of as little as 1 percent can reduce the life of the Claus catalyst in a Claus sulfur recovery plant from 3-5 years to 9-10 months. Consequently, the hydrocarbons contained in the rich waste gas stream would have to be removed before a Claus plant could be employed to control the hydrogen sulfide contained in this gas stream discharged from the Rectisol process.

Selective removal of the hydrogen sulfide from the rich waste gas stream, however, is much easier than selective removal of the hydrocarbons. Thus, this is the approach that has been taken by those companies that are planning to use a Claus sulfur recovery plant to control the hydrogen sulfide contained in the rich waste gas stream. Not only does this achieve the objective of removing the hydrocarbons from the gases processed by the Claus plant, but it also concentrates the hydrogen sulfide in these gases from about 5-40 percent to about 35-85 percent.

The waste gases discharged from a Claus sulfur recovery plant treating the "concentrated" rich waste gas stream discharged by the coal gas purification facilities in a coal gasification plant will contain in the range of 1/2-1 percent sulfur dioxide, or 5,000-10,000 ppm, although no hydrogen sulfide will be present. The technology for reducing these emissions further is well demonstrated.

Claus sulfur recovery plants are widely used in petroleum refineries to control hydrogen sulfide emissions. Although a refinery Claus plant normally treats a waste gas stream containing about 90 percent hydrogen sulfide, the waste gases discharged also contain about 1/2-1 percent sulfur dioxide because of the higher sulfur recovery efficiency achieved. At a number of refineries, the sulfur dioxide contained in these gases is then controlled by tail gas scrubbing. Use of the Wellman-Lord process, for example, will reduce sulfur dioxide emissions to 0.025 percent, or 250 ppm. This is, in fact, the standard of performance recently promulgated for new, modified, and reconstructed petroleum refinery sulfur recovery plants.

Technology for control of non-methane hydrocarbon emissions is also well demonstrated. The concentration of non-methane hydrocarbons in the waste gas streams discharged from the affected facilities in a Lurgi coal gasification plant will range from as little as 1-2 percent in the coal gasifier lock hopper gases and the by-product gas/liquid separation facilities to as much as 5-10 percent in the rich waste gas stream from the coal gas purification facilities. Incineration of waste gases containing similar concentration levels of non-methane hydrocarbons is quite common in the petroleum refining industry and the carbon black industry. With proper design and operation to achieve fire-box residence times of the order of 0.3 second and fire-box temperatures of 700-800 degrees centigrade, of non-methane hydrocarbons can be reduced to 0.01 percent, or 100 ppm.

4.2 CONTROL OF EMISSIONS FROM THE RECTISOL PROCESS

Because the announced Lurgi coal gasification plants have included only the Rectisol sulfur removal system, only this system has been considered

in evaluation of alternate emission control strategies. The Rectisol is not considered an emission control in itself, since sulfur removal is a process requirement. Sulfur recovery, which is not required, is then the emission control to be evaluated. For sulfur recovery the universally recognized processes include Claus sulfur plants, Stretford sulfur plants, and tail gas scrubbing for additional recovery from the Claus exhaust stream.

4.2.1 Rectisol Sulfur Removal¹

The original Lurgi Rectisol plant was built in Sasolburg, South Africa, in 1955 and has operated since then at about 97 percent on-stream factor. The Rectisol process uses one solvent (methanol) for removal of CO₂ and sulfur compounds, as well as other compounds in smaller amounts. Carbon dioxide and hydrogen sulfide are removed from process gases by physical absorption in the cold methanol at or below -40°F. The cold temperatures and organic nature of the solvent also permits the Rectisol to remove tars, oils, ammonia, phenols and other condensables. Various liquid streams may be removed from the Rectisol for recovery of the more valuable by-products, such as light oils, phenols, and ammonia. The disadvantages of the Rectisol are that some solvent loss to the product streams may occur and that the ethane and ethylene loss from the main process stream to the Rectisol off-gas streams is significant.

The ability of the Rectisol process to remove sulfur compounds is well demonstrated. For example, the original Rectisol unit in Sasolburg was designed to remove total sulfur to less than 1.3 ppm. Until 1964 the Rectisol averaged 0.3 ppm total sulfur but since that time has averaged around 0.02 ppmv or less due to process improvements.

One of the primary advantages of the Rectisol is in the case of subsequent sulfur recovery design. The methanol solvent is normally regenerated in stages;

and due to the difference in absorption between CO_2 and H_2S , the $\text{H}_2\text{S}/\text{CO}_2$ ratio in the gases released from each regeneration stage varies. As a result, the methanol regeneration section of the Rectisol process can be designed to produce one off-gas stream containing essentially all the CO_2 and H_2S or, at the extreme, one off-gas stream containing essentially all the H_2S and another containing the bulk of the CO_2 . Economic considerations, however, usually dictate against this extreme and lead to design of the regeneration section to produce either one off-gas stream or two off-gas streams with different H_2S concentrations. Limited Rectisol operating data on a coal gasifier are contained in Appendix C-1, Table C-1.1.

4.2.2 Sulfur Recovery of Acid Gases

No commercial or even pilot facilities currently exist which resemble the planned coal gasification plants with sulfur emission control systems discussed in this report. Transfer of control technology from similar industrial applications is therefore necessary to estimate the capabilities of sulfur control systems on coal gasification plants.

Table 4.1 provides a comparison of coal gasification acid gases to typically encountered industrial acid gases fed to control systems. Industrial applications where sulfur recovery is practiced include coke ovens, petroleum refineries and natural gas and oil production. As shown in Table 4.1, the gaseous species present in coal gasification acid gases are common to other industrial acid gases.

With the Rectisol process, acid gases should not differ markedly from acid gases which are presently being controlled in other industries. All of the domestic coal gasification plants in advanced planning stages show combinations of Stretford and Claus with and without tail gas scrubbing in the sulfur recovery section.^{2,3,4,5} It is assumed therefore that

Table 4.1. COMPARISON OF GASIFICATION ACID GASES TO OTHER INDUSTRIAL ACID GASES

Components (%)	Coal gasification*			Coke oven Stretford feed ^b	Natural gas straight-thru Claus feed ^c	Natural gas split-flow Claus feed ^d
	Rectisol rich H ₂ S	Rectisol lean H ₂ S	Combined acid gases			
CO	-	0.11	0.10	5.0	-	-
H ₂	-	0.24	0.23	61.0	-	-
CO ₂	67.33	97.90	96.38	2.0	18.5	78.68
HC	12.93	1.25	1.83	28.7	1.9	1.04
H ₂ S	17.54	0.49	1.34	0.4	73.7	19.72
COS	0.24	0.01	0.02	-	-	-
CS ₂	-	-	-	-	-	-
Other gases	1.96	-	0.10	2.9	5.9	0.56

*Intermediate sulfur coal feed of 1.2 lbs/10⁶ Btu input. Estimates calculated in Appendix C-2.

the Stretford and Claus processes can be applied to coal gasification plants.

4.2.3 Performance of Existing Sulfur Emission Control Systems

To assess the performance of sulfur recovery systems in coal gasification plants, the Stretford and Claus processes were investigated in other applications, noting the gas stream composition, operating conditions, and emission data.

Stretford process performance:

The Stretford process was examined on a low-Btu gas from a German coke oven.⁶ Coke oven gas is unlike coal gasification acid gas in that CO_2 and H_2S have not been concentrated. For the German coke oven, CO_2 is approximately 2 percent and H_2S 0.4 percent of raw gas, while combined coal gasification acid gases are normally 80-90 percent CO_2 and 1-2 percent H_2S .

Hydrogen sulfide in the process gas was continuously monitored by bubbling into a cadmium sulfate solution and measuring the precipitated sulfide. Inlet H_2S to the Stretford averaged 5 to 7 grams per normal cubic meter (gm/ncm). H_2S in the Stretford outlet was below the detectable limit of 0.125 ppmv. Detailed data are shown in Table C-1.4, Appendix C-1.

Claus plant performance:

An evaluation of the capability of a Claus plant to operate on the rich H_2S gas discharged from the Rectisol process indicates that this gas stream could not be processed by a Claus plant directly. Claus catalysts are quite sensitive to hydrocarbons and operation on this gas stream would lead to a rapid deterioration in sulfur recovery. As a result, the hydrocarbon content of the rich H_2S gas stream must be reduced to make it suitable for a Claus plant.

Selective removal of the hydrocarbons in this gas stream, however, would be difficult. Consequently, the approach taken by those companies that have chosen to employ the Claus process is selective removal of the H_2S using the Adip process developed by the Shell Oil Company. This approach also has the advantage of further increasing the H_2S concentration in the gases fed to the Claus plant.

The Shell Adip process employs an aqueous alkanolamine solution to selectively absorb the H_2S from the rich H_2S gas stream discharged by the Rectisol process. Regeneration of this solution through the application of heat releases a concentrated H_2S gas suitable for operation of a Claus plant.

Two Claus plants were evaluated by EPA, one for high sulfur feed incorporating the straight-through process, and the other for low sulfur feed incorporating the split flow process. EPA tests on the 3-stage high-sulfur (approximately 80 percent H_2S and 20 percent CO_2) Claus plant showed an average 96.9 percent recovery.⁸ Both tests are summarized in Appendix C-1, Tables C-1.5 and C-1.6.

EPA also gathered emission data from several petroleum refinery Claus plants having emission controls and gathered operator and local agency data to supplement the EPA test data.⁹ Figure 4.1 shows the data for the Wellman-Lord, Beavon, and SCOT processes. Emission levels were consistently well below 250 ppmv total sulfur. Overall sulfur recovery efficiencies exceeded 99.9 percent. Had these tests been conducted on low-sulfur Claus feeds, the resulting efficiencies would have dropped somewhat; however, the outlet sulfur concentrations, as dictated by the control process chemistry, should have remained at the low levels shown in Figure 4.1.

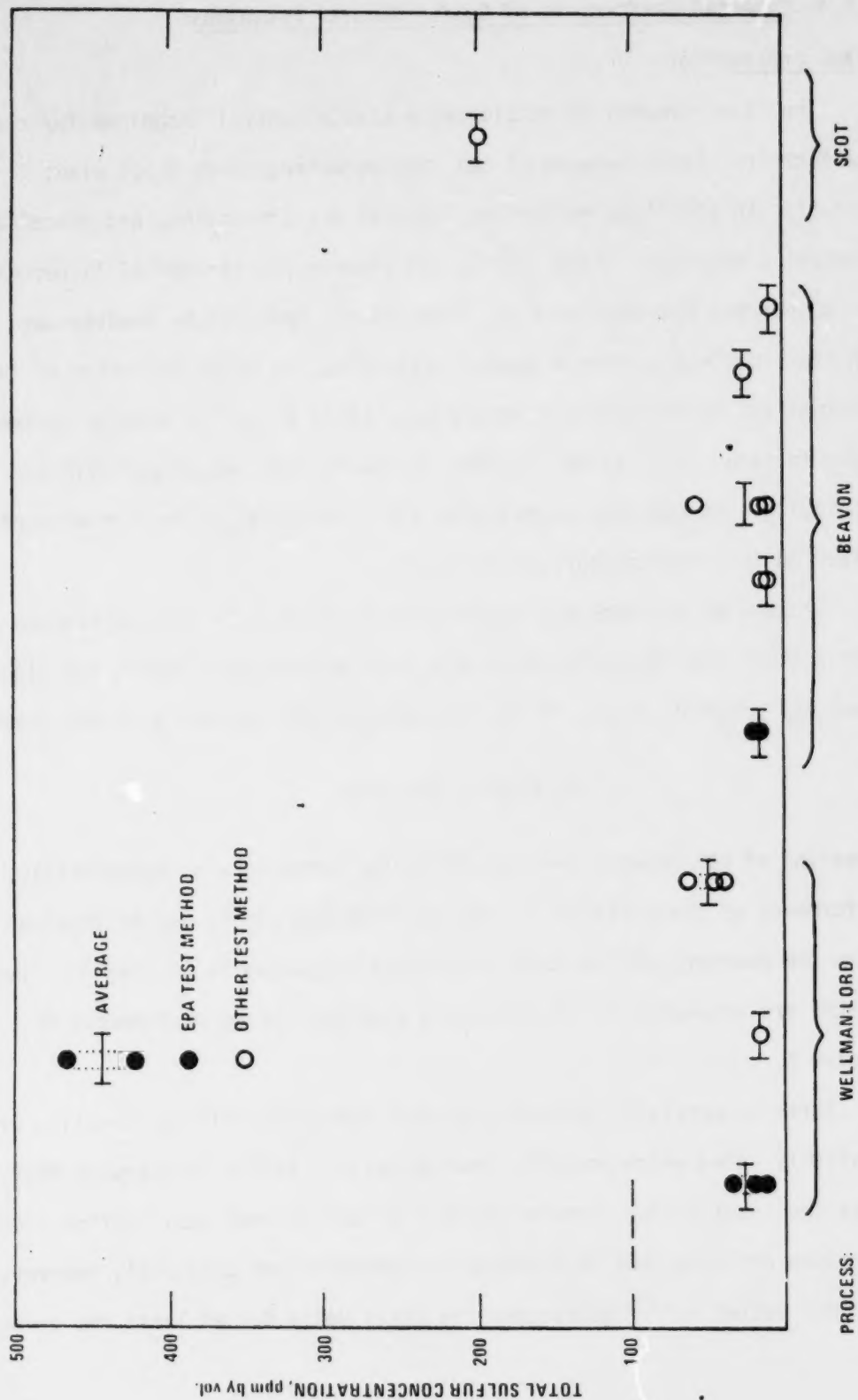


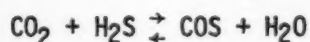
Figure 4.1. Sulfur emission data for Claus tail gas processes.

4.2.4 Expected Performance of Sulfur Removal Processes

Claus processing:

The Claus process is considered a viable control technique for coal gasification plants because of the vast experience with Claus plant operation in petroleum refineries, natural gas processing, and miscellaneous chemical processing. Claus plants can process gas streams of 15 percent to 100 percent hydrogen sulfide; although the more dilute feedstreams require a process variation termed split-flow, in which one-third of the original H₂S feedstream is oxidized completely to sulfur dioxide in the Claus furnace. This sulfur dioxide stream is then recombined with the original gas stream and reacted over the Claus catalyst to form elemental sulfur as in a conventional Claus plant.

Because of the high CO₂ concentrations present in the gas streams that a Claus plant would process in a coal gasification plant, the Claus plant may actually result in the formation of COS according to the reaction:



Formation of COS reduces the overall sulfur recovery and, consequently, the performance of Claus plants in coal gasification plants may be impaired below the recovery efficiencies previously mentioned in chapter 4. These adverse effects are accounted for in assessing expected system performance in chapter 6.

Three commercially operating systems for Claus tail gas treating were previously cited which normally improve overall sulfur recovery to 99.9 percent. Since the input sulfur streams are more dilute in coal gasification than in petroleum refining, the 99.9 percent recovery is not practical; however, the 250 ppmv outlet sulfur guarantees are still valid for at least one system,

the Wellman-Lord in which sulfur gases are incinerated to SO_2 and the SO_2 recovered in a basic scrubber solution. The licensor will guarantee 250 ppmv SO_2 for the high CO_2 streams indicated in Appendix C-2.¹⁰

Stretford sulfur recovery:

For more dilute sulfur streams in coal gasification plants (less than 10-15 percent by volume H_2S), the Stretford process will be used. Although most existing Stretford units operate on streams containing 1 percent H_2S or less, planned Lurgi gasification plants show Stretfords on streams containing up to 8.7 percent H_2S , with outlet H_2S designed for 50-100 ppmv.¹² Other reduced sulfur gases, such as COS , CS_2 , and mercaptans, are not removed by the Stretford.

4.2.5 Hydrocarbon and Carbon Monoxide Emission Controls

The only demonstrated system for the control of hydrocarbon and carbon monoxide emissions at the concentrations encountered in Rectisol off-gases is that of incineration. The best EPA data on the control of hydrocarbon and carbon monoxide emissions by combustion are found in tests conducted on carbon monoxide boilers at carbon black plants.¹³ The total hydrocarbons at a carbon black plant are similar to those in Lurgi-Rectisol off-gases, both in concentration (10,000 ppmv versus 11,000) and in the presence of methane and unsaturated hydrocarbons. In addition, carbon monoxide emissions are automatically controlled by conversion to carbon dioxide. This is in spite of the significantly higher level of uncontrolled CO emissions reported in the carbon black plants (1000,000+ ppmv versus 1,500 ppmv).

Tables C-1.10 and C-1.11 summarize the results of EPA tests for non-methane hydrocarbons and carbon monoxide from carbon monoxide boilers at carbon black plants. In general, emissions of hydrocarbons and carbon monoxide are both reduced to the 50-100 ppm range, hydrocarbons varying from 45 to 125 ppmv and carbon monoxide from 28 to 128 ppmv.

4.3 CONTROL OF EMISSIONS FROM OTHER SOURCES

As discussed in chapter 3, although the Rectisol process is by far the major emission source within the coal gasification process, a number of other emission sources exist. Control of emissions from these sources is discussed below.

4.3.1 Gasifier Lock Hoppers

The gasifier operates at relatively high pressure (i.e., ~400 psig). Control of the emissions contained in the gases released from the coal lock as it is depressurized depends on the gas employed to pressurize the lock initially. If an inert gas, such as N_2 or CO_2 is employed, the gases released from the coal lock as it is depressurized to about 250 psig can be collected in a gas header system for reuse in repressurizing the lock. Below 250 psig these gases would be of little use in repressurizing the coal lock. Also, since they contain little raw coal gas, they are of little value for producing additional SNG. Consequently, the gases released as the coal lock is depressurized below 250 psig would be vented to the atmosphere. This final depressurizing is accomplished by putting a slight vacuum on the lock through the use of air ejectors. As a result, the gases vented contain a high oxygen content which would present an explosion hazard if these gases were collected and compressed to route them to an incinerator or flare.

If, on the other hand, raw coal gas is used to pressurize the coal lock initially, the gases released from the lock as it is depressurized to about 0.5 psig can be added to the raw coal gas product from the gasifier for production of additional SNG. As with an inert gas, such as N_2 or CO_2 , however, final depressurization and evacuation of the lock is accomplished through the use of air ejectors. Consequently, residual gases released as the lock is depressurized below 0.5 psig would be vented directly to the atmosphere.

4.3.2 Sour Water Stripping

The gases discharged from sour water stripping to remove H_2S , NH_3 , and other contaminants can be compressed and routed to either the Stretford plant or the Claus plant operating on the gases discharged from the Rectisol process. Although these gases are low pressure, there is no oxygen present and, hence, no explosion hazard. Also, since their volume is small in comparison to that of the gases going to the Stretford or Claus plants from the Rectisol process, they do not significantly increase the size of these plants.

4.3.3 By-product Recovery

Although the gases released from the by-product recovery facilities contain hydrocarbons, H_2S and other reduced sulfur compounds, their volume is quite small and compression to route them to the Rectisol process would accomplish little. To ensure destruction of the contaminants contained in these gases, however, they could be routed to an incinerator.

4.3.4 Catalyst Regeneration and Start-up Gases

As discussed in chapter 3, these gases are intermittent in nature and, as a result, their contribution to overall emissions is minimal. Thus, compression of these gases to route them to the Rectisol process would be of little benefit. As with the by-product recovery gases, however, destruction of the contaminants contained in these gases could be achieved by incineration.

4.3 REFERENCES

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11. Letter, George L. Tilley, Union Oil Research, to Charles B. Sedman, ESED, OAQPS, EPA, dated January 2, 1976.
12. "Standards Support and Environmental Impact Statement: An Investigation of the Best Systems of Emission Reduction for Furnace Process Carbon Black Plants in the Carbon Black Industry," ESED, OAQPS, Research Triangle Park, North Carolina, April 1976, Appendix C.
13. Brochure "Sulfur Recovery Qualifications and Experience," J. F. Pritchard & Company, Kansas City, Missouri, September 1973, p. A-5.
14. Genco, Joseph M., and Tam, S. S., "Characterization of Sulfur Recovery from Refinery Fuel Gas," EPA Contract No. 68-02-0611, Battelle-Columbus Laboratories, June 1974, p. 30.

5. ALTERNATIVE EMISSION CONTROL SYSTEMS

5.1 GENERAL APPROACH

In Chapter 3 potential emissions from coal gasification processes were identified. In Chapter 4 the available emission control techniques and their expected performance was discussed. To formulate the alternative emission control systems which could serve as the basis for comparison of alternatives, the emission sources and control techniques were analyzed as discussed below.

5.1.1 Gas Stream Characterization

The approach to gas stream characterization was to obtain all the design data on planned domestic high-Btu gasification plants and actual gas stream data on existing foreign Lurgi installations. In addition, general coal gasification plant design considerations were provided through a contracted report by Booz-Allen. From these data it was concluded that a typical plant output would be 250×10^9 Btu per day of pipeline-quality gas with a coal to product gas thermal efficiency of 64.5 percent.

Realizing that the effects of coal feedstock variability would play an important role in assessment of alternative emission control systems, models were developed for both the expected extremes in feedstock sulfur and an "intermediate" sulfur feedstock. Emissions depend not only on the coal sulfur content, but also on the coal heating value. The coal heating value determines the amount of CO_2 discharged and the quantity of product gas produced, while the coal sulfur content determines the amount of H_2S discharged. The $\text{H}_2\text{S}/\text{CO}_2$ ratio in the waste gas streams discharged from the

Rectisol process determines the emission control system and its mass efficiency and is, therefore, a function of the sulfur/heating value ratio in the coal feedstock.

Of all coals which are candidates for first generation gasification plants, the following three coals were considered--a Western subbituminous coal of extremely low sulfur, a low-sulfur Western lignite, and a high-sulfur, mid-west bituminous coal. The respective sulfur/heating value ratios are 0.4, 1.2, and 3.6 pounds sulfur per million Btu's.

5.1.2 Assessment of Control Technique Performance

In making an assessment of the various emission control techniques, the following engineering assumptions were made:

1. The H_2S/COS ratio in the process gas feed to the Rectisol unit is 98.2/1.8, which, according to the Booz-Allen reports is the expected ratio following the water-gas shift reaction based on thermodynamic equilibrium.¹
2. A Stretford sulfur recovery plant will reduce the H_2S concentration in the tail gas stream to 100 ppmv, but will not reduce the COS content of the gas stream.
3. A Claus sulfur recovery plant will operate at a recovery efficiency of 95 percent. The level of COS , CS_2 and S_x in the tail gas is 0.06 volume percent.
4. Scrubbing of the Claus sulfur plant tail gas will reduce SO_2 concentrations to 250 ppmv (dry).
5. Tail gas incineration requires an exit temperature of 1600°F and 20 percent excess air. Product gas of 970 Btu/scf is the incinerator fuel.

All other data and engineering assumptions are consistent with those presented in Appendix C-1.

One difficulty in assessing the performance of the various control techniques is, to estimate the effects of unsteady-state processing. Looking at the available controls, both the Stretford sulfur plant and the Claus tail gas scrubbing unit are based upon the mass transfer of a pollutant from a gas stream to a liquid scrubbing media. Scrubbing systems can be designed to accommodate fluctuating gas flow rates and varying compositions and maintain the same end point gas concentrations.

The Claus sulfur plant, however, is based on a chemical reaction requiring a fixed stoichiometric ratio of H_2S and SO_2 to achieve optimum performance. A Claus plant operating with variable feeds, therefore, cannot be expected to achieve the performance of steady-state Claus plant operations, i.e. 96 to 97 percent sulfur recovery. With tail gas sulfur removal, however, the tail gas scrubber can accept the fluctuations and make up for the Claus' shortcomings.

5.2 ALTERNATIVE EMISSION CONTROL SYSTEMS

Figure 5.1 illustrates the major gas streams in the Lurgi SNG coal gasification process. Based on the use of Stretford and Claus sulfur recovery plants, two basic approaches emerge for controlling emissions, as shown in Figure 5.2. Of the five Lurgi SNG coal gasification projects currently under consideration for construction in the United States, two have tentatively selected the Stretford-Claus approach and three have tentatively selected the Stretford-only approach.

The overall emission control efficiency of these two approaches, however, differs. The Stretford-Claus approach achieves an overall sulfur control efficiency in the range of 93-95 percent, while the Stretford-only approach achieves an overall sulfur control efficiency in the range of 96-98 percent.

Figure 5.1. Major Gas Streams in Lurgi SNG Coal Gasification Plant

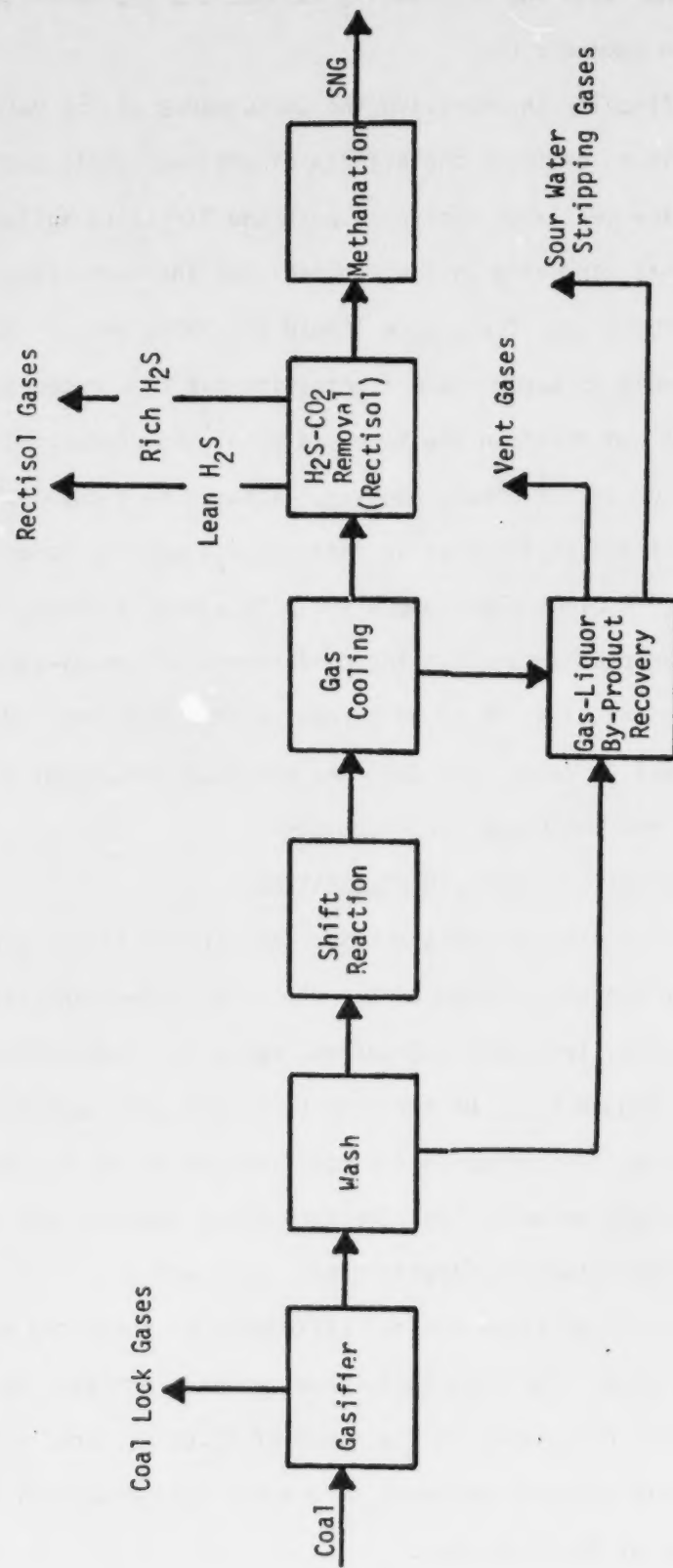
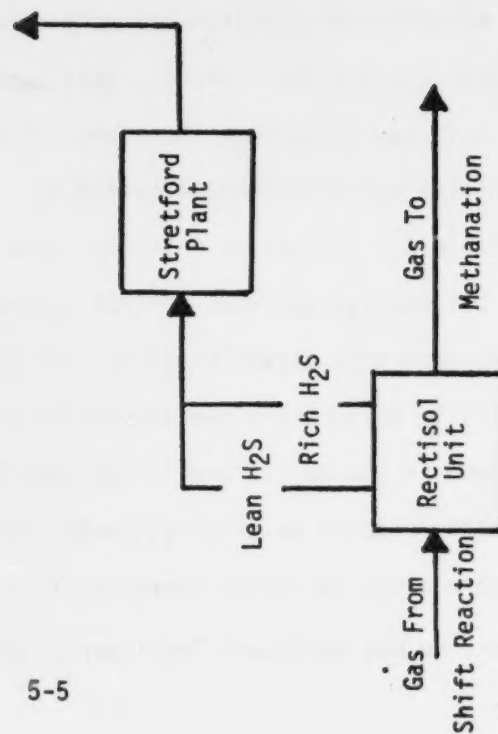
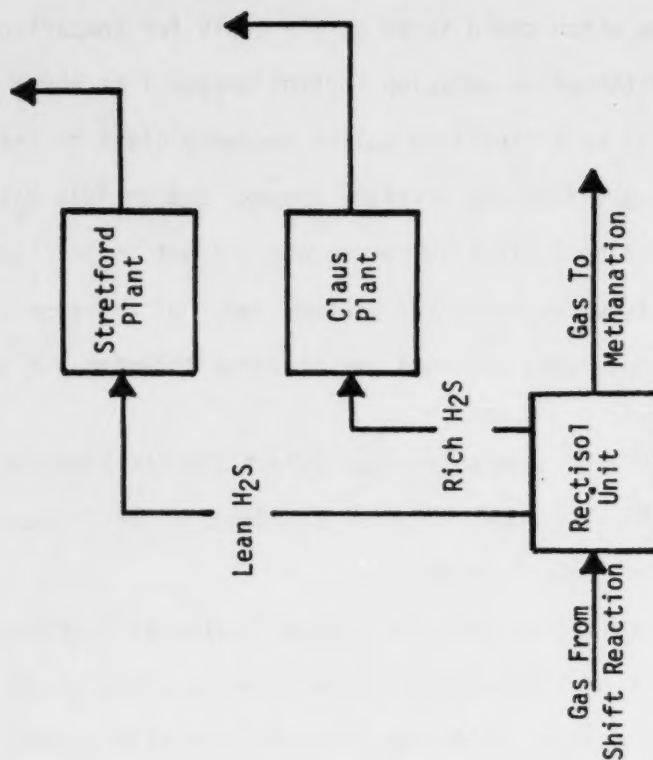


Figure 5.2. Alternative Approaches to Emission Control

Stretford-Only



Stretford-Claus



These two approaches, therefore, define the alternative emission control systems which could serve as the basis for comparison of alternatives.

Alternative emission control system I is shown in Figure 5.3 and consists of a Stretford sulfur recovery plant on the lean H_2S gas stream discharged from the Rectisol process and an Adip H_2S concentration plant followed by a Claus sulfur recovery plant on the rich H_2S gas stream. This alternative reflects the minimal level of emission control being considered by the emerging SNG coal gasification industry and thus represents the base case.

Those companies that select the Stretford-only approach would have no difficulty complying with standards of performance based on this alternative emission control system.

Alternative emission control system II is shown in Figure 5.4 and consists of a Stretford sulfur recovery plant on the combined lean and rich H_2S gas streams discharged from the Rectisol process. Those companies that select the Stretford-Claus approach would have to include tail gas scrubbing on the Claus plant tail gas to reduce emissions to a level comparable to the level of emissions obtained by applying a Stretford plant to the combined lean and rich H_2S gas streams. This approach, i.e., Stretford-Claus with Claus tail gas scrubbing, therefore, is included as one of the options under alternative emission control system II.

Table 5.1 summarizes emissions from a Lurgi coal gasification plant under alternative emission control systems I and II.

As mentioned above, these two alternative emission control systems essentially reflect the two approaches for controlling sulfur emissions contained in the gas streams discharged from the Rectisol process. Other alternatives could be developed reflecting partial or no control of the sulfur and hydrocarbon emissions contained in these gas streams. These alternatives, however, do not represent "real-world" options.

Figure 5.3. Alternative Emission Control System I

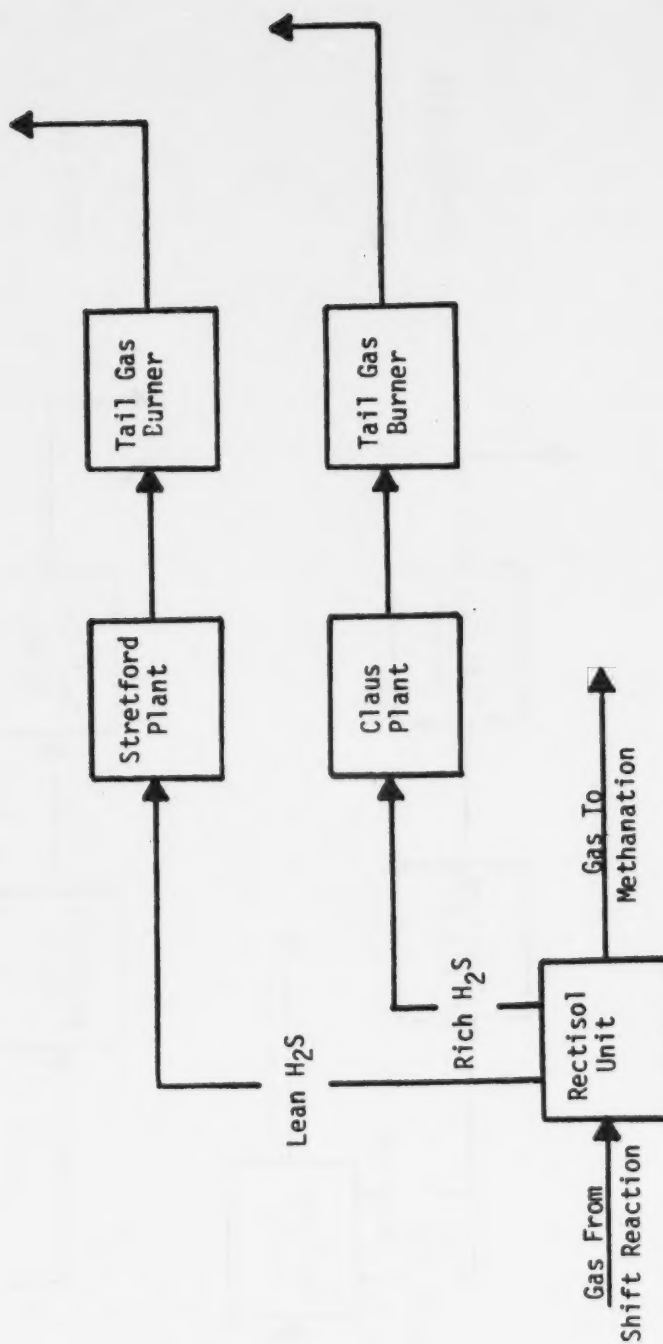


Figure 5.4. Alternative Emission Control System II

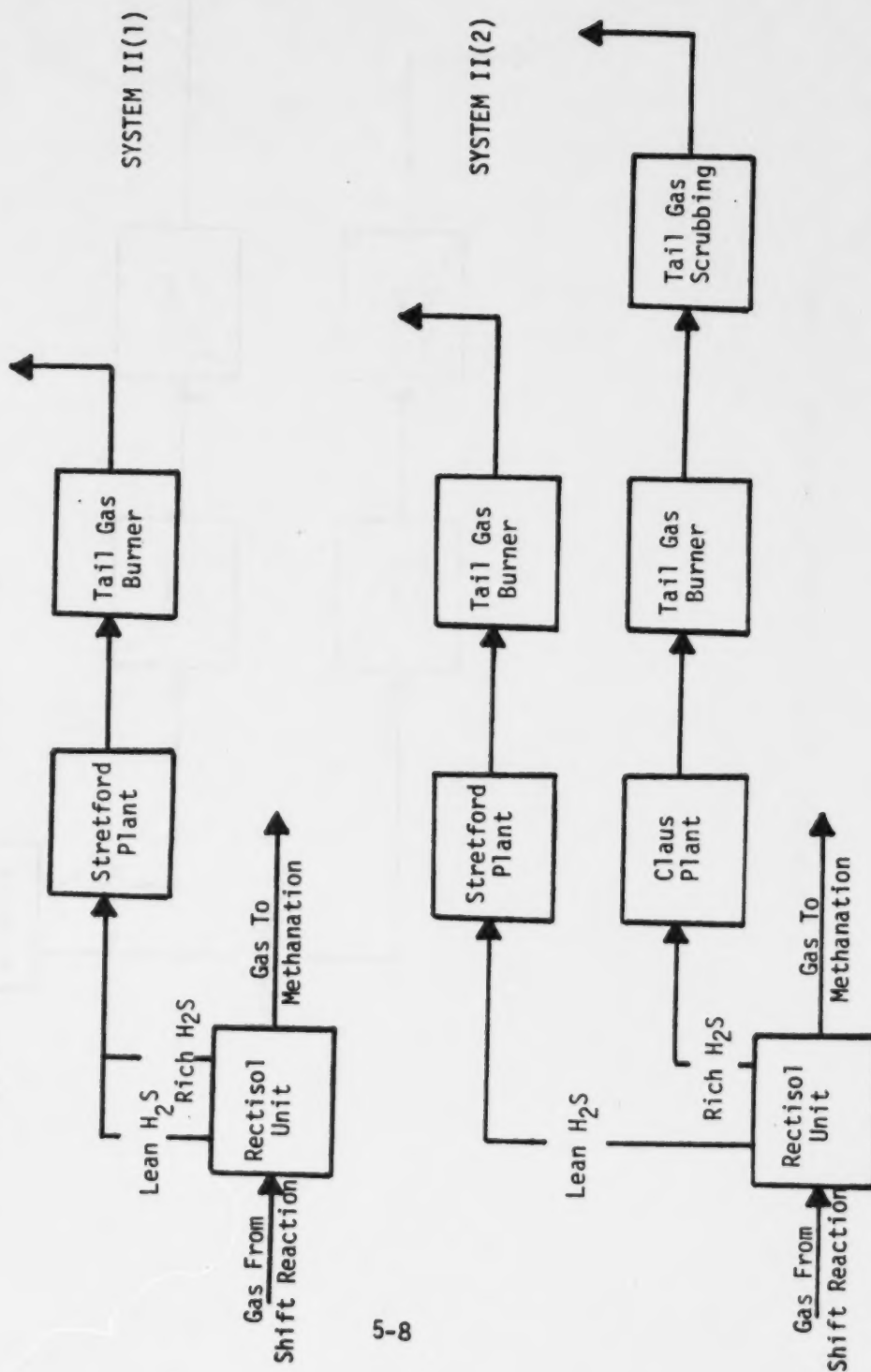


Table 5.1. EMISSIONS FROM A 250 BILLION BTU PER DAY LURGI SNG COAL GASIFICATION PLANT
WITH ALTERNATIVE EMISSION CONTROLS¹
(FROM APPENDIX C-II)

Pollutant	Uncontrolled			Alternative I			Alternative II					
	(a)	(b)	(c)	(a)	(b)	(c)	1(a)	1(b)	1(c)	2(a)	2(b)	2(c)
SO ₂	-	-	-	922	2234	6131	461	941	2285	474	973	2355
H ₂ S	5658	19,530	58,589	-	-	-	-	-	-	-	-	-
C ₂ ⁺²	17,559	17,559	17,559	250	250	250	250	250	250	250	250	250
Total Sulfur (as elemental sulfur)	5325	18,381	55,143	461	1117	3066	230	470	1142	237	486	1178
Sulfur Recovery, %	0	0	0	91.3	93.9	94.5	95.7	97.4	97.9	95.6	97.4	97.9

1. All numbers in lb/hr except where noted.
2. Non-methane hydrocarbons, average molecular weight = 29.

Table 5.2 summarizes the maximum ambient air concentrations of SO_2 and H_2S resulting from an uncontrolled and partially controlled Lurgi coal gasification plant, compared to those resulting from a plant controlled by alternative emission control system I and alternative emission control system II. While an uncontrolled Lurgi coal gasification plant could comply with the National Ambient Air Quality Standard (NAAQS) for SO_2 and the maximum incremental increase in ambient air SO_2 concentrations permitted under the prevention of significant deterioration regulations (PSD) for a class II area, the resulting ambient air concentrations of H_2S would lead to severe odor problems (the odor threshold for H_2S is $45 \mu\text{g}/\text{m}^3$), and injury to such crops as alfalfa, barley, and cotton. Partially controlling H_2S by installation of a Stretford sulfur recovery plant, or an Adip H_2S concentration unit followed by a Claus sulfur recovery plant on the rich H_2S waste gas stream discharged from the Rectisol process would not eliminate this odor problem, or prevent injury to sensitive crops, even though this waste gas stream contains about 65 percent of the H_2S .

Incineration of the lean waste gas stream discharged from the Rectisol process would eliminate both the odor problem and prevent injury to sensitive crops. The resulting increase in SO_2 emissions, however, would lead in many cases to ambient air concentrations of SO_2 in excess of both the NAAQS and the class II PSD increment for SO_2 . Consequently, sulfur emissions in both the rich and lean H_2S waste gas streams discharged from the Rectisol process will have to be controlled and both alternative emission control systems reflect this fact.

The situation with hydrocarbon emissions is analogous. Since sulfur emissions must be controlled, coal gasification plants will select either

Table 5.2. AIR QUALITY IMPACT OF POSSIBLE ALTERNATIVE EMISSION CONTROL SYSTEMS

Control System	Maximum Ambient Air Concentrations ¹						Hydrocarbons ²
	SO ₂			H ₂ S			
	3 hr	24 hr	Annual	1 hr	24 hr	Annual	
Uncontrolled	100-350 ³	10-50 ³	1-2 ³	550-12,200 ⁴	25-500 ⁴	1-30 ⁴	175-400
Partial Control							
See Note 5	100-600	10-70	1-5	170-4200	10-175	1-10	175-400
See Note 6	200-3200	25-400	2-20	-	-	-	50-150
Control System I	100-700	15-100	1-5	-	-	-	3-5
Control System II	100-450	10-70	1-5	-	-	-	3-5
NAAQS	-	365	80	-	-	-	160
PSD Increment	512	91	20	-	-	-	-

Notes:

1. All values in $\mu\text{g}/\text{m}^3$.
2. Non-methane hydrocarbons.
3. Due essentially to coal-fired power plant (controlled to meet NSPS of 1.2 lb SO₂ per million Btu fired).
4. Due essentially to coal gasification process.
5. Control of rich gas stream from Rectisol process - no control of lean gas stream.
6. Control of rich gas stream from Rectisol process - incineration of lean gas stream.

the Stretford-Claus or the Stretford-only emission control system. Where the Stretford-Claus approach is selected, the Claus plant will not be an emission source of non-methane hydrocarbons. As discussed earlier, any hydrocarbons present in the rich waste gas stream will be removed prior to the Claus plant in an H_2S concentration unit such as the Adip process.

If both the hydrocarbon waste gas stream discharged from the Adip process and the waste gas stream discharged from the Stretford sulfur recovery plant were released directly to the atmosphere, the resulting ambient air concentrations of non-methane hydrocarbons would exceed the National Ambient Air Quality Standard guideline for non-methane hydrocarbons, as shown in Table 5.2 (Note 5). More importantly, various studies have shown that release of these hydrocarbon emissions into the atmosphere would result in ambient air concentrations of oxidants exceeding the National Ambient Air Quality Standard for oxidants.² Partial control through incineration of the waste gas stream discharged from the Stretford sulfur recovery plant would reduce the resulting ambient air concentrations of non-methane hydrocarbons substantially, as shown in Table 5.2 (Note 6). In a number of cases, however, the ambient air concentrations would still come very close to the NAAQS and in reality would probably exceed the NAAQS on occasion. Consequently, as with sulfur emissions, control of hydrocarbon emissions is necessary and both alternative emission control systems reflect this fact.

Selection of the alternative emission control systems has focused only on the waste gas streams discharged from the Rectisol process. As discussed in Chapters 3 and 4, other emission sources exist within coal gasification plants. The Rectisol process, however, is by far the major and most significant emission source accounting for about 95 percent of the potential sulfur emissions and about 85 percent of the potential hydrocarbon emissions. Further-

more, for a number of these other emission sources, the obvious emission control technique is to combine the waste gas streams discharged with those discharged from the Rectisol process and control the combined gas stream. Consequently, it is the gas streams discharged from the Rectisol process that define the emission control problem and, for this reason, the above discussion has concentrated on the Rectisol process.

If only the Rectisol process is required to control emissions, however, uncontrolled emissions from these other emission sources would be the major contributor to emissions released to the atmosphere from Lurgi SNG coal gasification plants. Emissions from these other sources, therefore, are taken into account in Table 5.1 and both alternative emission control systems I and II assume control of the waste gas streams discharged from these sources as follows:

Coal gasifier coal lock:

(1) Pressurization of the coal lock with an inert gas such as N_2 or CO_2 with release of these gases, as the lock is depressurized to about 250 psig, to a gas collection and storage system for recycle to the coal lock when it is repressurized. Residual gases released as the lock is depressurized below 250 psig are released directly to the atmosphere.

(2) Or alternatively, pressurization of the coal lock with raw coal gas with release of these gases to the Rectisol emission control system as the lock is depressurized to about 0.5 psig. Residual gases released as the lock is depressurized completely are released directly to the atmosphere.

Sour water stripping:

Control of these gases in the Rectisol emission control system.

By-product recovery, catalyst regeneration and start-up:

Control of these gases by incineration or flares.

5.3 REFERENCES

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2. "Impact of Energy Resource Development on Reactive Air Pollutants in the Western United States," Contract No. 68-01-2801, Environmental Research & Technology, Inc., Westlake Village, California, February 1976.

6. ENVIRONMENTAL IMPACT

The two alternative emission systems presented in Chapter 5 were analyzed for their impact upon emissions, ambient air quality and significant deterioration, existing emission standards, water quality, solid wastes and energy expenditure. These impacts were compared to those of a coal gasification plant with no hydrocarbon or sulfur controls. The following discussion is based upon the environmental and energy impact calculations in Appendix C-2 and the dispersion analysis in Appendix C-3.

6.1 AIR POLLUTION IMPACT

6.1.1 Emission Reduction

In Chapter 5 the alternative emission control systems were presented and assessed on emission reduction capabilities. Table 6.1 shows the emission reduction of each emission control system option as calculated in Appendix C-2. These figures show direct emission reduction of sulfur, hydrocarbon, and carbon monoxide gases and direct emission increase of NO_x for each alternative control system. Significant reductions in emissions of sulfur hydrocarbons, and carbon monoxide are realized in all cases.

If control system option I is taken as a minimum control allowable under existing regulations, then option II would not reduce hydrocarbons and carbon monoxide. However, additional sulfur reduction is possible. Option II would remove an additional 1300 lbs SO_2 per hour for the intermediate case and 3700 lbs SO_2 per hour for the highest sulfur case.

Table 6.1. EMISSION REDUCTION² OF ALTERNATIVE EMISSION CONTROL SYSTEMS¹
(All figures in lb/hr)

Alternative Emission Control Systems									
Pollutant Removed (Emitted)	I			II					
	Control System			Control System					
	(a) Low	(b) Int.	(c) High	1(a) Low	1(b) Int.	1(c) High	2(a) Low	2(b) Int.	2(c) High
Sulfur (as SO ₂)	9,900	35,200	106,300	10,400	36,500	110,100	10,400	36,500	110,000
Non-methane HC	17,300	17,300	17,300	17,300	17,300	17,300	17,300	17,300	17,300
Carbon Monoxide	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO _x (as NO ₂)	(400) ³	(400)	(400)	(400)	(400)	(400)	(400)	(400)	(400)

¹Based on 250 x 10⁹ Btu/day SNG plant.

²Compared to uncontrolled plant.

³Quantity in parenthesis means an increase in emissions.

(a) Low sulfur coal = 0.4 pound sulfur per million Btu's.

(b) Intermediate sulfur coal = 1.2 pounds sulfur per million Btu's.

(c) High sulfur coal = 3.6 pounds sulfur per million Btu's.

6.1.2 Dispersion Model to Determine Incremental Air Quality Impact

A meteorological dispersion model has been used by the U.S. EPA Source-Receptor Analysis Branch for the evaluation of the control alternatives outlined in Chapter 5. The specific model employed was the aerodynamic effects version of the Single Source Dispersion Model (CRSTER) that was developed by the Meteorology Division, EPA. This is a Gaussian-type model capable of considering multiple emission points and complex aerodynamic effects. Assumptions made in this application of the model include the following:

1. Emission rates are constant.
2. Pollutants are nonreactive and non-depleting.
3. Terrain is relatively flat.
4. No "downwash" from nearby buildings or stacks.

6.1.3 Impact on Air Quality

A summary of the dispersion analysis is presented in Table 6.4. Air quality impact is shown as the maximum pollutant concentration in micrograms per cubic meter (mg/m^3) found in modeling. The distance from the emission point at which this maximum was found was not calculated.

Under current significant deterioration regulations, all proposed coal gasification plants would be required to incorporate best available control technology (BACT), which is as yet undefined. It has been assumed that coal gasification plants would incorporate alternative control system I to comply with the NAAQS for SO_2 and non-methane hydrocarbons under the prevention of significant deterioration regulations for a Class II region. Therefore, only alternative control system II could have an impact.

From Table 6.4 the impact of system II over system I with respect to ambient air quality is negligible for all cases. This is due to the overriding

Table 6.4 AIR QUALITY IMPACT OF ALTERNATIVE
EMISSION CONTROL SYSTEMS

Control System	Maximum SO ₂ Concentrations ($\mu\text{g}/\text{m}^3$)		Maximum H ₂ S Concentrations ($\mu\text{g}/\text{m}^3$)		Maximum Non-Methane Hydrocarbon Concentrations ($\mu\text{g}/\text{m}^3$)	
	3 hr.	24 hr.	1 hr.	24 hr.	1 hr.	3 hr.
Uncontrolled	100-350 ¹	10-50 ¹	550-12,200 ²	25-500 ²	1-30 ²	175-400
I	100-700	15-100	<1	<1	<1	3-5
II	100-450	10-70	<1	<1	<1	3-5
NAAQS	-	365	-	-	-	-
PSD Increment ³	512	91	-	-	-	-

Notes

1. Due essentially to power plant emissions.
2. Due essentially to coal gasification process.
3. Class II area.

effect of SO₂ emissions from the gasification steam boilers. Significant improvement in non-methane hydrocarbon levels is achieved, however, when either control alternative is used.

6.1.4 Impact Upon Existing Emission Standards

Although Federal Ambient Air Quality Standards generally limit air emissions overall, standards for coal conversion processes do not yet exist, except for the State of New Mexico.¹

Table 6.5 compares sulfur emission rates for each emission control system option to existing New Mexico standards. It should be noted that the New Mexico standards were promulgated based on the use of the subbituminous low-sulfur coal found in that region.

Incineration of all off-gases as in emission control systems I and II allows the plant to meet the New Mexico regulations for reduced sulfur and H₂S. However, the total sulfur standard, which includes oxidized sulfur, would be difficult to achieve under any emission control system for high-sulfur coal feed. Table 6.5 thus illustrates the importance of considering the sulfur and heating value of input coal in the development of emission standards.

6.2 WATER POLLUTION IMPACT

The wastewater effluent discharged from a coal conversion facility is typically derived from a combination of sanitary, domestic, sludge clarifier, gasification and control system purges, and ash treatment wastewater. Wastewaters from the gasification process normally originate from:

- ...Moisture driven off during coal drying
- ...Chemical wastewater from production unit operations
- ...Water from process chemical reactions
- ...Water from by-product recovery processes

Table 6.5 COMPARISON SULFUR EMISSION RATES FROM EMISSION CONTROL SYSTEM TO NEW MEXICO STANDARDS

[illegible]

These process-originated liquids are principal sources of pollutants since they come into direct contact with contaminants already present in the processing streams. However, most of the processes in the coal conversion scheme are net consumers of water. This consumptive characteristic allows much of these liquid streams to be recycled for use in the process. Since total consumption of these liquids is not technically and economically feasible, a small portion will require disposal.

The composition of the process-related liquid effluents from a coal gasification facility is expected to be a complex matrix of organic and inorganic compounds. In the organic fraction of liquid effluents, the major compounds are phenols, oils, and grease. Detergents, fatty acids, polynuclear and aromatic hydrocarbons, and sulfonated compounds may also be present in lesser quantities. The bulk of inorganic compounds are reduced and oxidized sulfurs, ammonia, cyanides, halogens, and multivalent metals. For non-process-related effluents, the composition is expected to be a mixture of both organic and inorganic compounds. These effluents are derived from the gasification facility's sanitary waste and indirect cooling streams and are not considered to be a principle pollutant source.

6.2.1 Plant Effluents Without Emission Control

Without the alternative emission control systems previously outlined, the gasification plant liquid effluents to be discussed have been based on values published by utility companies in conjunction with announced SNG facilities. Table 6.6 summarizes the data on water input, net consumption, and overall output rates obtained from these industry sources.^{2,3,4}

Approximately 6100 gallons per minute (gpm) of raw or input water is required for a typical coal gasification facility, exclusive of emission control systems and coal mining operations. Figure 6.1 presents the distribution and disposition of this water.

Table 6.6. MATERIAL BALANCE OF RAW INPUT WATER AND LIQUID WASTE FOR COAL GASIFICATION PLANTS

Company	Total Input Required* (gpm)	Net Amt. Consumed (gpm)	Net Output (gpm)*	
			To Atmos.	As Effluent
American Natural Gas	8,082	2,757	4,579	746
El Paso Natural Gas	5,622	1,266	3,456	900
Panhandle Eastern Pipe Line				
System # 1	4,367	1,262	2,802	303
System # 2	6,535	1,262	4,736	537
Western Gasification Company	5,700	1,120	4,136	444
Averages	6,061	1,533	3,942	586

*For entire facility, including process systems and support facilities.

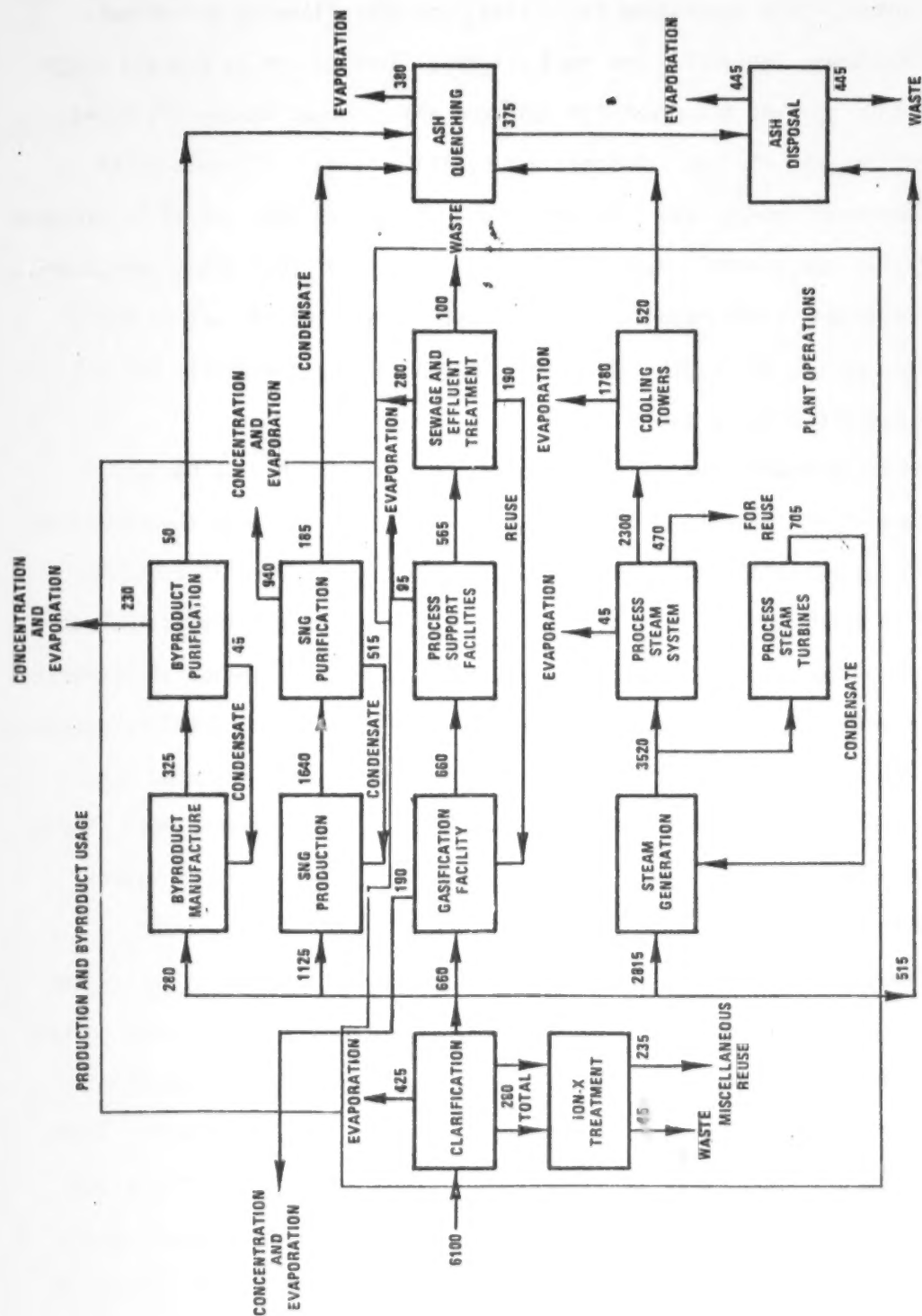


Figure 6.7. Liquid stream flow for typical high-Btu gasification facility.
(All values in gallons per minute.)

For plant operations, approximately 4180 gpm are used for pretreating the raw water, steam generating facilities, and miscellaneous operations, such as landscape irrigation and road wetting. Product and by-product usage is about 1400 gpm and the remaining 1265 gpm are consumed during treatment of the bottom ash, fly ash, sludges, and sanitary waste. Although these total plant requirements are 6845 gpm, about 750 gpm of this amount is produced internally as condensate, which is recycled to satisfy other plant requirements. Steam generation is the major consumer of water, using 46 percent of total plant consumption, while raw water clarification, other processes, and ash disposal require about 8 percent each.

From an environmental effects standpoint, approximately 65 percent or 3940 gpm of the plant's total consumption is discharged into the atmosphere as non-polluting water vapor. The amount actually discharged as a liquid effluent is about 590 gpm or 8.6 percent. Sources of waste streams include raw water treatment, ash disposal and sewage treatment. Examples of disposal receptors include surface water, deep wells, holding tanks or settling/evaporation ponds. Table 6.7 lists the probable major constituents and expected concentrations in the wastewater effluent from a typical gasification plant. These values have been derived from information supplied by the American Natural Gas Service Company (ANG).

6.2.2 Impact of Alternative Emission Control System Options Upon Wastewater

In general the liquid wastes produced by the alternative emission control systems originate from the Stretford process and Claus tail gas treating processes, with no significant streams expected from the Claus plant. These wastes consist of sour water condensate and/or the system's purge or bleed solutions. The compositions of the control system effluent, however, are quite different from that of the base plant without controls. To illustrate the waste stream differences, Table 6.8 shows the approximate composition of the purge streams from the Stretford and Wellman-Lord processes. [Compare to Table 6.9.]

Table 6.7 COMPOSITION OF THE WASTEWATER EFFLUENT
FROM A GASIFICATION PLANT WITHOUT SULFUR CONTROLS

Pollutant or Characteristic	ANG Lurgi Process (mg/l)	BuMines Synthane Process (mg/l)	Selected Base Plant Values (mg/l)	lb/day
BOD5	1,100	-	1,100	544.3
COD	3,150	1,700-43,000	3,150	1558.7
Ammonia (as N)	350	2,500-11,000	350	173.2
Phenols	80	200-6,600	80	39.6
Fatty acids	2,250	-	2,250	1113.3
Oil and grease	-	-	40 ^(a)	19.8
Total dissolved solids (TDS)	3,750	-	3,750	1855.6
Total suspended solids (TSS)	-	-	100 ^(b)	49.5
Cyanide	-	0.1-0.6	0.1	.05
Thiocynate	-	21-200	20	9.9
Sulfides	-	-	(10 ppm) ^(c)	70.8
Sulfates	30	0	30	14.8
pH range	6.5-7.0	7.9-9.3	6.6-8.6 ^(c)	

(a) NSPS for petroleum refineries, 70-890 lbs/10¹² Btu feedstock

(b) NSPS for petroleum refineries, 140-1,920 lbs/10¹² Btu feedstock

(c) Federal Water Quality Standard

Table 6.8 APPROXIMATE COMPOSITION OF LIQUID WASTE STREAMS FROM EMISSION CONTROL TECHNOLOGIES (a)

Wellman-Lord Process (b)			
Sour Water Condensate		Wellman-Lord Purge	
Component	Weight Percent	Component	Weight Percent
H ₂ SO ₄	10	Na ₂ SO ₄	5
H ₂ O	90	NaHSO ₃	7
		Na ₂ SO ₃	14
		Na ₂ S ₂ O ₃	~1(c)
		Na ₂ S ₂ O ₅	~1(c)
		H ₂ O	72
		Na ₂ CO ₃	0.47
		Na-ADS(d)	0.07
		Na-meta vanadate	0.03
		Na-citrate	0.03
		Na ₂ S ₂ O ₃	0.60
		NaSCN	0.60
		H ₂ O	98.20

(a) Genco, J. M. and Tam, S. S., "Characterization of Sulfur from Refinery Fuel Gas", report to U. S. EPA, Battelle-Columbus, March 1974.

(b) No centrifuge in system and water added to dissolve salts.

(c) Amount in solution unknown but conservatively estimated at about 1 percent by weight.

(d) Sodium anthraquinone disulfonate.

The composition of the liquid waste streams from each of the two alternative emission control systems include several potentially hazardous components or substances. These substances, in general, are unique to the control technologies involved and thus will contribute additional pollutants to wastewaters of coal gasification plants. If separate treatment of these wastes is warranted, several specific treating systems are commercially available and are discussed in Section 6.2.4.

Table 6.9 provides composition of the major pollutants in liquid waste streams from each alternative emission control system presented in Chapter 5. These wastes were determined using the composition of Table 6.7 with the assumption that (a) Stretford purge rates are uniform for each option at 10 gallons per pound-mole of gas fed to the Stretford, (b) Wellman-Lord wastes are 15 gallons of purge and 21 gallons of acid condensate per pound-mole of sulfur removal.

Assuming that a minimum of emission control is required [emission control system I as a base case], the only significant impacts upon liquid wastes occur where SO_2 scrubbing is used, i.e. emission control system II(2). The magnitude of this impact increases proportionally to the amount of sulfur in the original coal feedstock as shown in Table 6.9.

Compared to the base case, control system II(2) adds additional sodium values to the overall liquid wastes and, more significantly, a sizeable quantity of dilute sulfuric acid. The sodium in Wellman-Lord purge streams may be handled by the same disposal methods as the Stretford purge, although the amount of waste sodium is increased significantly. The dilute sulfuric acid stream (about 2 percent H_2SO_4 by volume) for the worst control system, case II(2)(c), is estimated at 29,700 gal/day.

Table 6.9 COMPARISON OF LIQUID DISCHARGE FOR ALTERNATIVE EMISSION CONTROL SYSTEMS

	Alternative Emission Control System									
	I					II				
	Control System					Control System				
	(a)	(b)	(c)	(a)	(b)	(c)	(a)	(b)	(c)	(a)
Components	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day	lb/day
Na ₂ CO ₃	3,900	4,000	4,100	3,700	3,700	3,800	3,900	4,000	4,100	4,100
Na-ADS	600	600	600	600	600	600	600	600	600	600
Na ₂ V ₂ O ₅	250	250	250	250	250	250	250	250	250	250
Na ₃ C ₆ H ₅ O ₇	250	250	250	250	250	250	250	250	250	250
Na ₂ S ₂ O ₃	5,000	5,000	5,200	4,800	4,800	4,800	5,200	5,600	7,000	7,000
Na ₂ S ₂ O ₅	-	-	-	-	-	-	200	600	1,800	1,800
NaSCN	5,000	5,000	5,200	4,800	4,800	4,800	5,000	5,000	5,200	5,200
Na ₂ SO ₄	-	-	-	-	-	-	1,000	3,000	8,800	8,800
NaHSO ₃	-	-	-	-	-	-	1,500	4,100	12,400	12,400
Na ₂ SO ₃	-	-	-	-	-	-	2,900	8,300	24,800	24,800
H ₂ SO ₄	-	-	-	-	-	-	2,900	8,300	24,800	24,800
H ₂ O	816,000	826,000	851,000	775,000	778,000	786,000	868,000	943,000	1,201,000	1,201,000
Total	831,000	841,000	867,000	789,000	792,000	800,000	881,000	983,000	1,292,000	1,292,000

(a) Low sulfur coal = 0.4 pound sulfur per million Btu's.
 (b) Intermediate sulfur coal = 1.2 pounds sulfur per million Btu's.
 (c) High sulfur coal = 3.6 pounds sulfur per million Btu's.

This normally would require neutralization before discharge; however, the uncontrolled plant waste of 1,201,000 gal/day would represent a 40/1 dilution of the weak acid when mixed with plant effluent. Hence, the impact of emission control system II represents a possible increase in sodium salts and a possible pH problem over emission control system I which would represent minimum controls.

6.2.3 Impact Upon Existing Liquid Effluent Standards

Although wastewater standards have not yet been promulgated for coal conversion processes, general regulatory policies restricting pollutant discharges have been established by federal, state, and local agencies. At the federal level, water pollutants are subject to New Source Performance Standards which affect new or modified facilities and processes. The majority of state and local agencies at the present time have formulated some type of policy or restriction on pollutant discharges. Most of these regulatory actions, however, are not as stringent as the Federal Performance Standards. While specific coal conversion wastewater standards do not exist, standards for two related processes have been promulgated. These processes include petroleum refineries and by-product coking plants. Their effluent limitations are summarized in Table 6.10 to illustrate the range and magnitude of these standards.

In general, the composition of wastewaters from coal conversion processes (reported in Tables 6.6 and 6.7) is expected to be unique when compared to wastewaters from other processes. Because of this difference, the wastewater compositions established for each selected control system alternative cannot be directly compared with the existing effluent standards shown in Table 6.10. Effluent limitations for such chemical substances as

Table 6.10 WASTEWATER EFFLUENT LIMITATIONS FOR PROCESSES
SIMILAR TO COAL CONVERSION PROCESSES*

Pollutant	Petroleum refineries (1b/1000 bbl feedstock ^a)	By- product coking (1b/1000 lb coke) ^b
	Maximum 30-day average ^c	
5-day biochemical oxygen demand (BOD5)	1.35-18.85	N/A ^d
Total suspended solids (TSS)	0.95-12.47	0.0104
Chemical oxygen demand (COD)	6.85-130.5	N/A
Oil and grease	0.43-5.80	0.0042
Phenolics	0.0098-0.1247	0.0002
Ammonia (as N)	0.28-11.02	0.0042
Sulfide	0.0073-0.1015	0.0001
Total chromium	0.0226-0.3045	N/A
Hexavalent chromium	0.00038-0.0052	N/A
pH (for all categories)	6.0-9.0	6.0-9.0
Cyanides amenable to chlorination	N/A	0.0001

^a6.5 billion Btu total (assumes HHV of 6.5 million Btu/bbl oil).

^b17.4 million Btu total (assumes HHV of 12,000 Btu/lb coal with coke
yield of 0.69 lb/lb coal).

^cDaily limits not included here. Refinery ranges reflect EPA promulgations
as of May 1974.

^dNot applicable.

sodium meta vanadate and sodium thiosulfate have not been established on a federal, state, or local level. In addition, the toxicity and behavior of these substances in various media or receptors are not well known.

6.2.4 Liquid Effluent Treatment and Disposal Options

Considering the uncertainty of future effluent guidelines for coal gasification and the lack of current regulations for the effluents generated by the emission control system, the impact is unclear. However, the ability of the plant to handle additional effluents from emission controls is better defined.

Several gasification plant programs propose discharge of plant liquid wastes into an approved receptor, e.g. a deep well. This practice, however, requires meticulous environmental monitoring. If discharge without treatment is acceptable, further concentrating of pollutants in these waste streams are avoided, thereby increasing the desirability of well disposal and realizing considerable cost savings. However, if the capacity or condition of the environment for receiving these liquid wastes is inadequate or sensitive, treatment, of course, will be necessary. Gasification facilities are designed to include sewage treatment plants which include: evaporation to concentrate the liquid, precipitation to coagulate or flocculate the pollutants, and absorption (ion exchange) to remove the pollutants.

Should the above techniques not be satisfactory for handling emission control liquid wastes along with process liquid wastes, several specific methods may be applied to handle the Stretford and Wellman-Lord purge streams.

The Stretford purge may be treated by at least two commercially available processes. One process developed by Nittentu Chemical Engineering, Ltd. (NICE) reclaims the sodium salts by evaporation and thermal decomposition and returns the sodium salts to the Stretford absorber.⁶ No liquid or solid effluent results from the process, although sodium sulfate is recovered as a by-product.

One vendor of the Stretford process also offers a similar process, in which all effluents are eliminated and all vanadium and sodium salts are recovered.⁷

It is not known if any of the effluent treatment systems for Stretford purge are in commercial use, due to the limited Stretford application in areas with strict effluent guidelines.

Waste streams from regenerable SO_2 scrubbing may also be treated by either of the above processes, since the effluents are very similar. One vendor of a regenerable SO_2 scrubbing process currently offers purge treatment steps ranging from drying for chemical sales or solid disposal to complete recycling of the sodium in a closed loop process.⁸ As with the Stretford purge treatment, commercialization of these processes has been limited due to lack of demand.

6.3 SOLID WASTE IMPACT

The bottom ash from both the gasifiers and coal-fired steam boilers represents over 90 percent of the total solid waste generated by a coal gasification facility.^{9,10} Fly ash, at about 6 percent, and solids

contained in the sludge streams totaling 3 percent, make up the remaining portion of the facility's solid waste. These waste products are normally not reprocessed, recycled, or subjected to extensive treatment, but merely pretreated and conveyed offsite to an appropriate disposal area. For the Lurgi gasification facility without emission controls the ash and sludge wastes originate from the following:

- ...Gasifiers (bottom ash)
- ...In take or raw water clarifier system (sludge)
- ...Effluent treatment system (sludge)
- ...Sanitary sewage treatment system (sludge)
- ...Coal-fired steam generator (bottom and fly ash)

6.3.1 Plant Solid Wastes Without Emission Control

The total amount of solid waste generated by a typical $(250 \times 10^6 \text{ ft}^3/\text{day})$ high-BTU coal gasification plant is expected to be approximately 6600 short tons (dry) per average day (ST/D), exclusive of emission control solid pollutants and salable by-products.¹¹ This estimated output is based on the following assumptions:

- ...Over 90 percent of the waste is bottom and fly ash
- ...Total coal consumption (gasification and steam generator) is 28,900 short tons/day
- ...Ash content of the coal is 22 percent (dry)
- ...Sludge is produced at 45.5 lbs per 1000 gallons of intake water (treated at 6100 gpm flow rate) and 47 lbs per 1000 gallons of effluent water (treated at 590 gpm flow rate).

Outlined in Table 6.11 are the sources, estimated quantities and general composition of each type of solid waste. The values indicated are considered to be representative of coal gasification plants in general. They were based on the available data from four plants presently being designed to produce SNG on a commercial basis.

6.3.2 Impact of Alternative Emission Control Systems Upon Solid Wastes

The solid wastes generated by the emission control systems are expected to consist primarily of spent reaction catalyst and dried solids from various purge streams. These solid waste products are typically derived from chemical compounds used only in emission control processes. These solids, therefore, are not similar to the base plant's waste, which consists of ash and sludges.

Since the solid waste is unique to each emission control technology, a comparison with the base plant output will not provide a meaningful basis to evaluate the alternative emission control systems. In the comparative assessment of the emission control system, only the system's solid waste outputs are compared and evaluated with respect to their effect on the environment.

Table 6.12 presents a comparison of the incremental uncontrolled solid waste outputs from the alternative emission control system. The alumina, Al_2O_3 is used as a catalyst in the Claus acid-gas sulfur removal process, which is a part of each emission control system. It likely will require total replacement every two years. All systems utilize the Stretford process, which generates a mixture of sodium salts, including a sodium vanadium salt,

Table 6.11. SOURCE, OUTPUT AND COMPOSITION OF SOLID WASTES
FROM A TYPICAL HIGH-BTU GASIFICATION PLANT

Source	Waste type	Dry Solids (ST/d)	Water (ST/d)	Wt. % Water	Total (ST/d)	General composition
Gasifier	Bottom ash	5,800	1,800	24	7,600	multivalent metals, inert compounds, cations ^a
Raw water clarifier system	Sludge	200	200	50	400	calcium salts, multivalent metals, ^b minerals, lime ^b
Effluent water treatment system	Sludge	20	20	50	40	tar, sand, coal, bio-treating chemicals ^b
Sanitary sewage treatment system	Sludge	<0.5	3	99	3	multivalent metals, organic compounds, bio-treating chemicals ^b
Coal-fired steam generators	Bottom ash	150	50	25	200	multivalent metals, inert compounds, cations ^a
	Fly ash	400	120	23	520	multivalent metals, inert compounds, cations ^a
	Dry solids	<0.02	-	-	<0.02	zinc oxide (sulfided)
TOTALS		6,570	2,570		8,763	

^aMixtures of oxides, carbonates, pyrophosphates, silicates, and other compounds in combination with elements listed in Table VI-1.

^bExact composition is not known.

Table 6.12. COMPARISON OF SOLID WASTES FROM ALTERNATIVE EMISSION CONTROL SYSTEMS

	Alternative Emission Control Systems						
	I			II			
	Control System			Control System			
	(a)	(b)	(c)	1(a)	1(b)	1(c)	2(a) 2(b) 2(c)
Components (lb/day)							
Claus Catalyst*	10	40	120	—	—	—	10 40 120
Purge Solids**	14,960	15,140	15,600	14,210	14,260	14,400	20,740 31,680 65,140
Total	14,970	15,180	15,720	14,210	14,260	14,440	20,750 31,720 65,260

*Annualized Daily Average, replaced infrequently, approximately every two years

**For breakdown by compound, refer to Table 6.10.

$\text{Na}_2\text{V}_2\text{O}_5$, which may be objectionable based on the known toxicity of vanadium, a heavy metal. System II(2) utilizes the Wellman-Lord process which also generates sodium salts, though less objectionable than the Stretford salts. Control systems are available to recover and recycle all sodium salts back to the process.

6.3.3 Impact Upon Existing Solid Waste Standards

In August 14, 1974, EPA established guidelines for the thermal processing and land disposal of solid wastes. These guidelines apply to facilities that are either in the design phase or are presently operating and processing 50 tons or more per day of domestic solid wastes. The land disposal aspect of the guidelines pertains to the resulting residue from the thermal processing of the solid waste and the manner in which this residue can be disposed.

In general, the guidelines detail the facility's design requirements and recommended facility operational procedures in the area of air and water quality, aesthetics, vectors (pathogen carrying organism), site selection, safety, residue disposition, record keeping, gas building control, and waste handling systems. These guidelines will not apply to gasification facilities, however, as the solid wastes generated by gasification plants should be far less than the 50 tons/day required for enforcement of the Federal guideline.

At the present time, solid waste standards specific for coal conversion plants have not been promulgated. Since these standards do not exist, a direct comparison of the waste output from each emission control system cannot be presented. Leachate, fugitive dust, odors, and gaseous releases

are some of the major problems of solid waste disposal which may be applicable to each of the alternative emission control systems. Thus, the impact of each alternative emission control system upon solid waste standards cannot be made until waste disposal methods (meeting specified pollutant criteria) have been determined.

6.4 ENERGY IMPACT

For the typical Lurgi gasification plant producing 250×10^9 Btu/day of SNG, roughly 440 billion Btu/day is consumed in operating the total gasification complex. This estimate is based on information submitted by several companies which showed a typical SNG Btu output to coal Btu input ratio of about 0.57.

6.4.1 Energy Impact of Alternative Emission Control System Options

The energy consumed by each emission control system was calculated based on the following assumptions:

- ...All gas streams that were incinerated used product SNG as fuel.
- ...Waste heat from incineration at 1600°F with 20 percent excess oxygen is recovered by generation of steam and preheating of intake air.
- ...All steam is produced by steam boilers at 80 percent thermal efficiency, except for low pressure steam produced by the Claus process.
- ...All electricity is produced from coal-fired generators at 34 percent thermal efficiency.

Calculations of energy impact are presented in Appendix C-2 and tabulated in Table 6.13. As shown, the energy requirements range from about 16 to 24.5×10^9 BTU/day, or 3.6 to 5.6 percent of the uncontrolled plant energy requirements of 440×10^9 BTU/day. If emission control system I is chosen as base control, then the following conclusions may be drawn from Table 6.13:

...Addition of Claus plant tail gas controls results in a two to four percent increase in control system energy consumption.

...If hydrocarbons are controlled by incineration, energy requirements, regardless of sulfur input, will average 3 to 5 percent of total plant requirements.

The energy impact of emission controls is significant; however the energy requirements of emission control system II compared to I shows no significant impact. If each 10^6 RTU were assumed to be equivalent to 1.2 lb SO_2 , 0.7 lb NO_x , and 0.2 lb particulate, the overall reduction in emissions of each alternative emission control system would be as shown in Table 6.14.

Table 6.14 shows that the reductions in sulfur, hydrocarbons, and carbon monoxide outweigh the resulting hypothetical emission increases in SO_2 , particulate, and NO_x at the coal-fired power plant or steam boiler for all cases.

Table 6.13. ENERGY CONSUMPTION OF ALTERNATIVE EMISSION CONTROL SYSTEMS
(BTU x 10⁶/day)

Alternative Emission Control Systems											
	I					II					
	Control System					Control System					
	(a)	(b)	(f)	1(a)	1(b)	1(c)	2(a)	2(b)	2(c)		
Stretford	296.81	1013.42	3081.48	856.64	3011.23	9078.10	296.81	1013.42	3081.48		
ADIP	496.63	1722.74	5172.03	-	-	-	496.63	1722.74	5172.03		
Claus	(418.32)	(1442.61)	(4411.51)	-	-	-	(418.32)	(1442.61)	(4411.51)		
Claus Incineration	216.84	446.16	1151.28	-	-	-	216.84	446.16	1151.28		
Wellman-Lord	-	-	-	-	-	-	152.88	430.42	1289.02		
Stretford Incineration	15312.96	15348.84	15202.20	15621.84	15599.06	15532.92	15312.96	15348.84	15202.20		
Total	15904.92	17088.55	20195.48	16478.48	18610.29	24611.02	16057.80	17518.97	21484.50		

() = net gain

Table 6.14. OVERALL EMISSION REDUCTION OF ALTERNATE EMISSION CONTROL SYSTEMS
(all units in lb/hr)

	Alternative Emission Control Systems									
	I			II						
	Control System			Control System						
	(a)	(b)	(c)	1(a)	1(b)	1(c)	2(a)	2(b)	2(c)	
Net Pollutant Removed*:										
Sulfur (as SO ₂)	9,900	35,200	106,300	10,400	36,500	110,000	10,400	36,500	110,000	
Non-methane HC	17,300	17,300	17,300	17,300	17,300	17,300	17,300	17,300	17,300	
Carbon monoxide	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	
Pollutant Directly Emitted										
NO _x (as NO ₂)	(400)	(400)	(400)	(400)	(400)	(400)	(400)	(400)	(400)	
Pollutant Indirectly Emitted										
SO ₂	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	
NO _x	(500)	(500)	(600)	(500)	(500)	(700)	(500)	(500)	(600)	
Particulate	(100)	(100)	(200)	(100)	(100)	(200)	(100)	(100)	(200)	
Net Benefit lb/hr										
Sulfur (as SO ₂)	9,100	34,300	105,300	9,600	35,600	108,900	9,600	35,600	108,900	
Non-methane HC	17,300	17,300	17,300	17,300	17,300	17,300	17,300	17,300	17,300	
Carbon monoxide	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	
NO _x	(900)	(900)	(1000)	(900)	(900)	(1100)	(900)	(900)	(1200)	
Particulate	(100)	(100)	(200)	(100)	(100)	(200)	(100)	(100)	(200)	

*Includes pollutant removed less pollutant directly emitted.
()=Net gain.

Assuming again that base control is used (system I), the incremental impact of emission control system II shows SO₂ reductions of 500 to 3600 lb/hr versus incremental increases in NO_x of 0 to 100 lb/hr and particulate increases of 0 to 100 lb/hr.

In summary, the secondary effects of increased energy consumption do not detract significantly from the benefits of alternative emission control system II compared to system I.

6.5 OTHER ENVIRONMENTAL IMPACTS

The only other environmental concern with coal gasification plants involves noise emissions. Booz-Allen Research conducted a study of anticipated noise emissions from coal gasification plants and each of the alternative emission control system. Their findings may be summarized by:

- ...No definitive noise data are available on multiple sources such as the emission control system for gasification plants.
- ...Total plant noise levels may produce occupational hazards requiring safety equipment.
- ...Projected plant sitings are such that the general public would be unaffected by gasification plant noise emissions.
- ...The contribution to plant noise by sulfur removal and recovery technique is insignificant and does not warrant a detailed environmental assessment.

6.6 OTHER ENVIRONMENTAL CONCERNS

No environmental impacts other than those discussed above are likely to arise from coal gasification plants using emission control systems I or II.

6.7 REFERENCES

1. "Comparative Assessment of Coal Gasification Emission Control Systems", EPA Contract No. 68-01-2942, Task 007, Booz-Allen Applied Research, Bethesda, Maryland, October 1975, pp. IV-38.
2. Letter E. L. Irwin, Western Gasification Company, to Don R. Goodwin, ESED, OAQPS, EPA, dated November 7, 1975.
3. Letter Charles R. Bowman, El Paso Natural Gas Company, to Don R. Goodwin, ESED, OAQPS, EPA, dated September 23, 1975.
4. Letter, Noel F. Mermer, American Natural Gas Service Company, to Don R. Goodwin, ESED, OAQPS, EPA, dated July 11, 1975.
5. Reference 4.
6. Mitachi, K., Chemical Engineering 80 (21) 78-79 (October 15, 1973).
7. Brochure "The Stretford Process" Woodall-Duckam USA Ltd., Pittsburgh, Pa. (1975).
8. Brochure "W-L SO₂ Pollution Control", Wellman Power Gas, Inc., Lakeland, Florida (1974).
9. Reference 1, page VI-1.
10. Reference 4.
11. Reference 1, page VI-5.

7. COSTS

7.1 COST ANALYSIS OF ALTERNATIVE EMISSION CONTROL SYSTEMS

Two model coal gasification plants have been developed, each representative of a typical new plant in the industry. Although their production capacities are identical (250 billion Btu per day of pipeline gas), the model plants differ in the type of wastewater treatment facilities employed.

Specifically, the New Mexico model, by virtue of its arid location, contains a lined solar evaporation pond for treatment of all process liquid wastes--including those generated by the emission control systems.

Due to winter freezing problems, coal gasification plants built in the midwest or in Rocky Mountain regions cannot use evaporation ponds. They must employ other means for liquid waste disposal. Therefore, for the midwestern model, costs have been developed for separate methods to treat liquid waste streams from the Stretford and Wellman-Lord plants.

In this section, costs are presented for the two alternative emission control systems presented in chapter 5, as they are applied to the two coal gasification model plants. The first alternative reflects the minimal emission control level at a new plant. Three cases are costed for this alternative, each representing a certain coal sulfur content.

If used, the second alternative would allow a plant to further reduce emissions of sulfur. Moreover, two options have been costed for this second alternative, each representing use of a particular control configuration.

Each option, in turn, is also costed for the three coal sulfur contents. (Refer to chapter 5 for more detail.)

In addition, each alternative includes incineration of all exhaust gases before release to the atmosphere. For this reason, hydrocarbon emissions (approximately 770 moles per hour in an uncontrolled plant) are oxidized to negligible amounts.

Costs for these two alternative emission control systems have been based on technical parameters associated with the control configurations, such as the design volumetric flowrates and amounts of sulfur removed. These parameters are listed in Table 7-1.

Because these are model plant costs, they cannot be assumed to reflect costs of any given new installation. Estimating control costs at an actual installation requires performing detailed engineering studies. For the purposes of this analysis, however, model plant costs are considered to be sufficiently accurate.

Some model plant costs have been based on data available from an EPA contractor (Booz-Allen-Hamilton).⁹ Other data have been obtained from natural gas companies who plan to construct coal gasification plants in this country.¹⁰⁻¹³ In addition, information has been extracted from several EPA reports: one containing procedures for estimating flue gas desulfurization system costs;¹⁴ another, a source of costs for solar evaporation ponds;¹⁶ the SSEIS for sulfur control at crude oil and natural gas field processing plants;¹⁵ and finally, a compendium of costs for selected air pollution control systems.¹⁸

Two cost parameters have been developed: installed capital and total annualized. The installed capital costs for each alternative emission control system include the purchased costs of the major and auxiliary equipment, costs for site preparation and equipment installation, and design engineering costs. No attempt has been made to include costs for research and development, possible lost production during equipment installation, or losses during startup. All capital costs in this section reflect first quarter 1977 prices for equipment, installation materials, and installation labor.

The total annualized costs are made up of direct operating costs, annualized capital charges, and recovery credits. Direct operating costs include fixed and variable annual costs such as:

- o Labor and materials needed to operate control equipment;
- o Maintenance labor and materials;
- o Utilities which include electric power, fuel, cooling and process water, and steam;
- o Treatment and disposal of liquid wastes.

The annualized capital charges account for depreciation, interest, administrative overhead, property taxes, and insurance. The depreciation and interest have been computed by use of a capital recovery factor, the value of which depends on the depreciable life of the control configuration and the interest rate. (An annual interest rate of 10 percent and a 15-year depreciable life have been assumed.) Administrative overhead, taxes, and insurance have been fixed at an additional 4 percent of the installed capital cost per year.

Table 7-1. PARAMETERS USED IN DEVELOPING MODEL PLANT SULFUR CONTROL COSTS^a

Alternative Emission Control System (Coal Sulfur Content) ^b	Control Configuration ^c	Total Volumetric Flowrate (lb-mole/hr)	H ₂ S Feed Rate (lb-mole/hr)	Sulfur Removed (LT/day)	Overall Sulfur Control Efficiency(%)	Wastewater Flowrate to Treatment System(s) (gal/hr)
I(A)	Stretford	39,500	56.6	18.1	92.5	3,950
	Adip	1,810	105	0		0
	Claus	301	109	35.9		0
	Stretford incinerator/waste heat recovery	1,060 ^e	4.5	0		0
	Stretford incinerator/waste heat recovery	89,100 ^e	3.9	0		0
I(B)	Stretford	39,600	196	65.8	95.0	3,960
	Adip	2,070	363	0		0
	Claus	379	379	125		0
	Stretford incinerator/waste heat recovery	2,390 ^e	12.6	0		0
	Stretford incinerator/waste heat recovery	89,200 ^e	3.9	0		0
I(C)	Stretford	40,000	587	200	95.5	4,000
	Adip	2,800	1,090	0		0
	Claus	1,330	1,140	376		0
	Stretford incinerator/waste heat recovery	6,300 ^e	37.9	0		0
	Stretford incinerator/waste heat recovery	89,100 ^e	4.3	0		0
II(1)A	Stretford	41,800	166	55.6	95.7	4,180
	Stretford incinerator/waste heat recovery	90,300 ^e	4.2	0		0
II(1)B	Stretford	42,000	574	195	97.5	4,200
	Stretford incinerator/waste heat recovery	90,300 ^e	4.2	0		0

Table 7-1. (cont.) PARAMETERS USED IN DEVELOPING MODEL PLANT SULFUR CONTROL COSTS^a

Alternative Emission Control System ^b (Coal Sulfur Content)	Control Configuration ^c	Total Volumetric Flowrate (lb-mole/hr)	H ₂ S Feed Rate (lb-mole/hr)	Sulfur Removed (LT/day)	Overall Sulfur Control Efficiency (%)	Wastewater Flowrate to Treatment System(s) (gal/hr)
II(1)C	Stretford	43,300	1,720	589	98.0	4,330
	Stretford incinerator/waste heat recovery	90,300 ^e	4.2	0		0
II(2)A	Stretford	39,500	56.6	18.1	96.7	3,950
	Adip	1,810	105	0		0
	Claus	301	109	35.9		0
	Wellman-Lord	1,060	0	2.4		250
	Claus incinerator/waste heat recovery	1,060 ^e	4.5	0		0
II(2)B	Stretford incinerator/waste heat recovery	89,100 ^e	3.9	0	98.4	0
	Stretford	39,600	196	65.8		3,960
	Adip	2,070	363	0		0
	Claus	571	379	125		0
	Wellman-Lord	2,390	0	6.8		710
II(2)C	Claus incinerator/waste heat recovery	2,390 ^e	12.6	0	98.8	0
	Stretford incinerator/waste heat recovery	89,200 ^e	3.9	0		0
	Stretford	40,000	587	200		4,000
	Adip	2,800	1,090	0		0
	Claus	1,330	1,140	376		0
	Wellman-Lord	6,240	0	20.2	98.8	2,120
	Claus incinerator/waste heat recovery	6,300 ^e	37.9	0		0
	Stretford incinerator/waste heat recovery	89,100 ^e	4.3	0		0

^aReference: EPA estimates

^bCorresponding coal sulfur contents are: A-0.4 lb/million BTU; B-1.2 lb/million BTU; C-3.6 lb/million BTU.

^cRefer to Chapter 5 for illustrations and detailed descriptions of the control systems.

^dLT = long ton = 2,240 lb.

^eThis is the volumetric flowrate at the incinerator outlet. All others are inlet flowrates.

^fEfficiency here is defined as the total sulfur removed by the Claus and Stretford units divided by the total sulfur fed to those units.

The credits account for the value of the sulfur and steam recovered with some of the emission control systems. The unit credits for these commodities have been based on what values they would have in the market place. (These values, along with the unit costs for labor, utilities, maintenance, etc., appear in Tables 7-2 and 7-3).

The total annualized cost is then obtained simply by adding the direct operating cost to the annualized capital charges, and subtracting the various credits from this sum.

Alternative Emission Control Systems

As stated previously, each of the two alternative emission control systems includes one or more kinds of sulfur control. These are: Stretford units, Claus units, Wellman-Lord units, and incinerators with waste heat recovery. Individually, these units consist of different kinds of process equipment (e.g., reactors, absorbers); however, for purposes of this analysis, they will be treated as single pieces of equipment, since their designs are more or less standard. (The process details for these units are given in Chapter 4.)

As stated earlier, the Midwestern model plant includes means for treating the Stretford and Wellman-Lord waste water streams. With the Stretford treatment unit, sulfuric acid is first added to the purge water, oxidizing the thiosulfate salts to sulfates. The stream is then piped to a refrigerated crystallizer, where the sulfates are crystallized and removed. The liquor containing valuable ADA (anthraquinone disulfonic acid) and vanadium catalyst is recycled to the Stretford unit, producing a recovery credit.

Table 7-2. ALTERNATIVE EMISSION CONTROL SYSTEM COSTS FOR NEW MEXICO MODEL PLANT^a

I. Installed Costs (M\$): ^b	Emission Control System I			Emission Control System II		
	Coal Sulfur Content:			Coal Sulfur Content:		
	A	B	C	A	B	C
Stretford	2,120	5,240	13,070	4,660	12,770	34,540
Claus	2,570	3,990	11,420	--	--	--
Adip	1,400	2,950	5,700	--	--	--
Incinerator/waste heat recovery (Claus)	480	750	1,320	--	--	--
Incinerator/waste heat recovery (Stretford)	6,220	6,230	6,190	6,300	6,290	6,270
Wellman-Lord (Claus only)	--	--	--	--	--	--
Solar evaporation pond (Incremental) ^c	980	980	980	1,040	1,050	1,080
Total Installed Cost	13,770	20,140	38,680	12,000	20,110	41,890
II. Annual Costs (M\$/yr): ^d						
Operating labor (\$5 10/man-hr)	158	158	158	79	79	79
Maintenance ^e	567	834	1,572	548	953	2,041
Cooling water (\$0.10/M gal)	6	19	57	--	--	--
Process water (\$0.25/M gal)	2	6	17	5	17	50
Boiler feed water (\$0.40/M gal)	171	182	211	168	168	167
Electric power (\$0.03/kwh)	277	947	2,871	746	2,625	7,916
Steam ^f	(10,344)	(10,479)	(10,557)	(10,492)	(10,390)	(10,099)
Fuel (\$0.35/M Btu)	24,304	24,713	25,588	24,445	24,408	24,304
Chemicals ^g	52	185	558	74	259	777
Sulfur recovery credit (\$0.25/long ton)	(439) ^h	(1,540)	(4,703)	(459)	(1,609)	(4,860)
Depreciation and interest (0.1315 x Total Installed Cost)	1,811	2,648	5,086	1,578	2,644	5,509
Taxes, insurance and administrative charges (0.04 x Total Installed Cost)	551	806	1,547	480	804	1,676
Total Annualized Cost	17,116	18,479	22,405	17,172	19,958	27,560

^aReferences 9, 11 to 16 and 18.

^bThroughout, "M" signifies thousands; "MM", millions, etc.

^cThat portion of the solar pond installed cost attributable to sulfur controls; the incremental annual cost is assumed to be zero.

^dAll annual costs have been based on an operating factor of 7,920 hours per year (24 hours per day and 330 days per year).

^eFor Claus plants, a figure of 3 percent per year of the installed cost has been used for maintenance labor and materials; for Adip plants, 3.5 percent has been employed; for all others, 5 percent has been employed.

^fThe unit value for steam varies according to the pressure. Herein, the following unit values have been used: 60 lbs per square inch: \$1.25/M lbs.; 600 lbs per square inch: \$2.50/M lbs.; 1200 lbs per square inch: \$3.00/M lbs. Hence, both the annual steam cost (credit) and the weighted unit value depend on the respective quantities and pressures of steam consumed or produced.

^gFor the Stretford and Wellman-Lord configurations, the chemicals usage has been based on the amount of sulfur recovered by each. The unit costs used for this item were: Stretford, \$4 per long-ton sulfur; Wellman-Lord, \$50 per long-ton sulfur. For the Adip plants, chemicals unit cost was \$0.001 per pound of H₂S removed.

^hParentheses indicate a credit.

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Table 7-3. ALTERNATIVE EMISSION CONTROL SYSTEM COSTS FOR MIDWESTERN MODEL PLANT^a

I. Installed Costs (\$K): ^b	Emission Control System I			Emission Control System II		
	A	B	C	A	B	C
Stretford	2,120	5,240	13,070	4,660	12,770	34,540
Claus	2,570	3,990	11,420	--	--	2,120
Adip	1,400	2,950	5,700	--	--	2,570
Incinerator/waste heat recovery (Claus)	400	750	1,320	--	--	1,400
Incinerator/waste heat recovery (Stretford)	6,220	6,230	6,190	6,300	6,290	6,220
Wellman-Lord (Claus only)	--	--	--	--	--	480
Stretford purge water treatment	9,200	9,220	9,270	9,530	9,550	9,220
Wellman-Lord purge water treatment	--	--	--	--	--	750
Total Installed Cost	21,990	28,380	46,970	20,490	28,610	50,540
II. Annual Costs (\$K/yr): ^c						
Operating labor (0 \$10/man-hr)	158	158	158	79	79	279
Maintenance ^d	567	834	1,572	548	953	2,041
Cooling water (0 \$0.10/M gal)	6	19	57	--	--	6
Process water (0 \$0.25/M gal)	2	6	17	5	17	50
Boiler feed water (0 \$0.40/M gal)	171	182	211	168	168	171
Electric power (0 \$0.03/kwh)	277	947	2,871	746	2,625	7,916
Steam ^e	(10,344)	(10,479)	(10,557)	(10,492)	(10,390)	(10,099)
Fuel (0 \$3.35/M Btu)	24,304	24,713	25,588	24,445	24,408	24,304
Chemicals ^f	52	185	558	74	259	777
Wastewater treatment ^g	(2,597)	(2,604)	(2,633)	(2,761)	(2,776)	(2,869)
Sulfur recovery credit (0 \$25/long ton)	(439)	(1,540)	(4,703)	(459)	(1,609)	(4,860)
Depreciation and interest (0.1315 x Total Installed Cost)	2,892	3,732	6,177	2,694	3,762	6,646
Taxes, insurance, administrative charges (0.04 x Total Installed Cost)	890	1,135	1,879	820	1,144	2,022
Total Annualized Cost	15,929	17,288	21,195	15,867	18,640	26,174
						16,543
						18,440
						23,648

^aReferences 9 to 11, 13 to 15, 17 and 18.^bThroughout, "M" signifies thousands; "MM", millions, etc.^cAll annual costs have been based on an operating factor of 7,920 hours per year (24 hours per day and 330 days per year).
^dFor Claus plants, a figure of 3 percent per year of the installed cost has been used for maintenance labor and materials; for ADIP plants, 3.5 percent has been used; for all others, 5 percent has been employed.^eThe unit value for steam varies according to the pressure. Herein, the following unit values have been used (reference 5):
60 lbs per square inch: \$1.25/MBtu; 600 lbs per square inch: \$2.50/MBtu; 1200 lbs per square inch: \$3.00/MBtu. Hence, both the annual steam cost and the weighted unit value depend on the respective quantities and pressures of steam consumed or produced.^fFor the Stretford and Wellman-Lord configurations, the chemicals usage has been based on the amount of sulfur removed by each. The unit costs used for this item are: Stretford, \$4 per long tonsulfur; Wellman-Lord, \$50 per long tonsulfur. For the Adip plants, chemicals unit cost was \$0.001 per pound of H₂S removed.^gThis item includes labor, maintenance, and utilities costs for operating the Stretford and Wellman-Lord purge water treatment methods. It also includes credits for recovered catalyst and chemicals. The depreciation, interest, taxes, insurance, and administrative

Crystallization is also employed by the Wellman-Lord treatment unit-- in this case, to recover sodium sulfate crystals from the purge stream. These crystals are assumed to be sold to other plants at fifty percent of the current market price of \$60 per ton.^{10,17}

The costs associated with the alternative emission control systems are listed in Tables 7-2 and 7-3. Each of these systems is summarized below; more details are available in Chapter 5.

Alternative Emission Control System I

As stated previously, both alternative systems consider treatment of three off-gases, each representing a different coal sulfur content. These off-gases and the corresponding sulfur contents are:

Case A: 0.40 pounds per million BTU

Case B: 1.2 pounds per million BTU

Case C: 3.6 pounds per million BTU

System I is designated as the baseline control alternative for coal gasification plants. This system consists of a Stretford sulfur recovery unit, followed by an incineration/waste heat recovery unit, to control the lean H_2S gas stream discharged from the Rectisol process. The rich H_2S gas stream is first directed to an Adip plant where the H_2S is concentrated and the hydrocarbons are removed. The concentrated H_2S stream is then sent to a Claus sulfur recovery unit, while the hydrocarbons are conveyed to the Stretford incinerator. Depending on the coal sulfur content, the overall sulfur control efficiency for System I ranges from 91.3 and 94.5 percent (See Table 7-1).

The two sulfur recovery units differ considerably in their operating features. A Stretford unit will reduce the H_2S concentration in the tail gas stream to 100 ppmv, but will not reduce the stream's COS content.

This translates to an overall sulfur control efficiency of 96 to 98 percent for the Stretfords. Although the Claus unit operates at a somewhat lower recovery efficiency (about 95 percent), it controls all sulfur compounds, not just the H_2S . Moreover, Claus units cannot tolerate hydrocarbons in their feedstreams, which is why Adip plants are needed in the systems.

The incinerator/waste heat recovery units operate at a $1600^{\circ}F$ combustion temperature and 20 percent excess air. Product gas with a 970 BTU heating value is used as the incinerator fuel. The waste heat recovered generates high pressure steam (1200 PSIG at $885^{\circ}F$), which is used elsewhere in the gasification plant.

As Tables 7-2 and 7-3 indicate, the total installed costs for system I range from \$13.8 million (case A, New Mexico) to \$47.0 million (case C, Midwestern). This cost difference is primarily due to the relative amounts of sulfur removed by the Stretford and Claus units for cases A and C: 54.0 and 576 long tons per day, respectively. The installed cost of the Stretford (primarily a function of the amount of sulfur removed) here ranges from \$2.1 million (case A) to \$13.1 million (case C), while the Claus costs increase over 400 percent, from \$2.6 to \$11.4 million. Also a factor is the much higher installed cost of the Stretford waste water treatment unit in the Midwestern model plant, relative to the incremental cost of the evaporation pond.

The total annualized costs for system I range from \$15.9 to \$22.4 million/year, respectively, for cases A (Midwestern) and C (New Mexico). Based on production at 100 percent of the capacity rate of 250 billion BTU per day; for 90 percent of the time (i.e., 7,920 hours per year), the

corresponding unit annualized costs are 0.19 and 0.27 dollars per million BTU (MMBTU). (See Table 7-4.) The major portion of the direct operating costs are for fuel, electric power, and maintenance. The sulfur recovery credits are also substantial, running from about \$0.4 to \$4.7 million/year. There are also net steam credits of about \$10.5 million/year for each of the three cases, attributable to the incinerator-waste heat recovery unit. However, these steam credits are more than offset by the fuel costs of \$24.3 (case A) to \$25.6 (case C) million/year.

Alternative Emission Control System II

System II consists of two options, as stated previously. The first option includes a Stretford sulfur recovery unit on the combined lean and rich H_2S gas streams discharged from the Rectisol process, followed by an incinerator/waste heat recovery unit. This Stretford-only option yields sulfur control efficiencies ranging from 95.7 to 97.9 percent, depending on the sulfur content. This efficiency range occurs because the Stretford H_2S outlet concentration (100 ppmv) is independent of the inlet loading. In other words, the higher the inlet loading, the higher the efficiency. As chapter 5 states, those plants using this option would have no difficulty complying with new source standards.

Tables 7-2 and 7-3 illustrate that the installed cost for this option ranges from \$12.0 (case A, New Mexico) to \$50.5 million (case C, Midwestern). This spread reflects again the range in Stretford unit costs, as well as the higher cost of the Stretford waste water treatment units. Interestingly, the cost of the Stretford incinerator-waste heat recovery unit is the same (about \$6.3 million) for the three cases. This is so because the incinerator unit installed cost is a function of the gas flowrate, not the off-gas sulfur loading. As Table 7-1 indicates, this flowrate is virtually the same for all cases.

Table 7-4. MODEL PLANT CONTROL COST SUMMARY^a

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Alternative Emission Control System (Coal Sulfur Content)	Control Configuration	Sulfur Control Efficiency (%)	Total Installed Cost (MM\$)	New Mex. Model	Midwest Model	New Mexico Model (MM\$/yr)	Midwestern Model (MM\$/yr) ^b	Total Annualized Cost (\$/MMBTU) ^b
I (A)	Stretford; Claus; Adip Incineration/Waste Heat (Stretford);	91.3	13.8	22.0	17.1	0.21	15.9	0.19
I (B)	Incinerator/ Waste Heat (Claus)	93.4	20.1	28.4	18.5	0.22	17.3	0.21
I (C)		94.5	38.7	47.0	22.4	0.27	21.2	0.26
II (1) (A)	Stretford; Incinerator/ Waste Heat Recovery	95.7	12.0	20.5	17.2	0.21	15.9	0.19
II (1) (B)		97.4	20.1	28.6	20.0	0.24	18.6	0.23
II (1) (C)		97.9	41.9	50.5	27.6	0.33	26.2	0.32
II (2) (A)		95.6	15.2	23.8	17.7	0.21	16.5	0.20
II (2) (B)	Stretford; Claus; Adip; Incinerator/ Waste Heat (Claus)	97.4	22.8	31.7	19.5	0.24	18.4	0.22
II (2) (C)	Incinerator/Waste Heat (Stret); Wellman-Lord (Claus)	97.9	43.9	55.4	24.6	0.30	23.6	0.29

^aReferences 9 to 18 and EPA estimates.

^bThe total annualized cost divided by the production rate assuming 90 percent capacity utilization (82.5 trillion BTU per year).

Regarding annualized costs, the tables show that fuel and power comprise the bulk of the operating, offset somewhat by credits for sulfur, steam, and (in the case of the Midwestern models) chemicals and catalyst recovered by the Stretford waste water treatment unit.

The annualized cost ranges from \$15.9 (case A, Midwestern) to \$27.6 million/year (case C, New Mexico). These translate to \$0.19 to \$0.33/MMBTU, respectively. Compared with System I, this option represents an annualized cost increase of 0 to \$0.06/MMBTU.

Option 2 of System II is identical to System I, except that a Wellman-Lord unit is added to scrub the SO_2 from the Claus incinerator tail gas. The Wellman-Lord reduces the SO_2 concentration to 250 ppmv (dry) in the Claus tail gas. Consequently, the sulfur control efficiencies with option 2 are higher than for System I: they range from 95.6 to 97.9 percent.

The option 2 installed costs range from \$15.2 (case A, New Mexico) to \$55.4 million (case C, Midwestern), which correspond well with the respective System I costs: \$13.8 and \$47.0 million. The differences are attributable to the added costs of the Wellman-Lord units, and (with the Midwestern models) the Wellman-Lord waste water treatment units.

The option 2 annualized costs range from \$16.5 (case A, Midwestern) to \$24.6 million/year (case C, New Mexico) or \$0.20 to \$0.30/MMBTU. This represents an annualized cost increase of 0 to \$0.03/MMBTU, relative to System I, the baseline. Since the only difference between the two control systems is the addition of Claus tail gas treatment, this increment is completely due to increased sulfur control.

7.2 OTHER COST CONSIDERATIONS

In addition to the costs detailed in Section 7-1, there are additional costs mandated by existing EPA air pollution standards. These costs consist of fly ash precipitation, SO_2 removal from the process steam generators flue gas, and opacity control for the coal handling equipment. Table 7-5 details these costs. Again these cover a New Mexico model plant and a Midwestern model plant.

Since both models use approximately the same coal feed rate, the control costs for the coal handling system will be the same. These costs represent the installation of fabric filters in both primary and secondary screening operations and the control of conveyor transfer points with the use of water sprays containing a surface active agent. Fabric filter costs were developed from methodology provided by an EPA contractor.¹⁸ The water spray system was based on costs developed for similar applications by the Bureau of Mines.¹⁹ The total capital requirement is \$639,000 and the annualized cost is \$213,000.

Existing Federal New Source Performance Standards will also apply to the steam generators. The New Mexico plant uses low Btu gas that has been desulfurized. Hence no particulate control nor flue gas desulfurization will be required. On the other hand the steam generators in the Midwestern model plant are coal fired. Each of the four will require an electrostatic precipitator for particulate collection for a total investment of \$12,000,000 and a total annualized cost of \$2,650,000. Sulfur dioxide is removed from the flue gas by two parallel Wellman Lord units costing \$7,000,000 each. Annualized costs for the two are \$3,350,000.

Both plants are rated at 250 million standard cubic feet per day. Assuming a 90 percent utilization factor, the additional controls will add 8.4¢/mscf at the midwestern plant and 0.34¢/mscf at the New Mexico plant.

Table 7-5. Other Costs Incurred Due to Existing Federal Standards.

	<u>Midwest</u>		<u>New Mexico</u>	
	<u>\$Capital</u>	<u>\$Annualized</u>	<u>\$Capital</u>	<u>\$Annualized</u>
Coal Cleaning				
Wet Suppression	\$ 380,000	\$ 80,000	\$380,000	\$ 80,000
Fabric Filters	259,000	133,000	259,000	133,000
Boiler Fly Ash	12,000,000	2,650,000	--	--
Boiler SO ₂	<u>14,000,000</u>	<u>3,350,000</u>		
Totals	\$26,639,000	\$6,213,000	\$639,000	\$213,000
Capacity MMSCFD	250	250		250
¢/MSCF @ 90% Capacity		8.4		0.3

References for Chapter 7

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8. ENFORCEMENT ASPECTS

8.1 SELECTION OF THE POLLUTANTS AND THE AFFECTED FACILITIES

Although the first commercial coal gasification plants constructed in the United States will use the Lurgi coal gasification process, a number of other coal gasification processes are under development. The data and information base available, however, is limited to the Lurgi process. The emission characteristics of other coal gasification processes may differ substantially from those of the Lurgi process. Consequently, this guideline document only pertains to coal gasification process.

8.1.1 Selection of Pollutants

Lurgi coal gasification plants will be major emission sources of particulate matter, sulfur dioxide, NO_x , non-methane hydrocarbons and carbon monoxide. Within a coal gasification plant, the primary point source which accounts for essentially all the NO_x emissions and most of the particulate matter emissions is the steam generating and super-heating facilities. These facilities also account for about one-third of the uncontrolled sulfur compound emissions. The standards of performance promulgated for fossil-fuel-fired steam generators (40 CFR Part 60, §§60.40-60.46), however, will limit emissions of particulate matter, NO_x , and sulfur dioxide from these facilities in any new coal gasification plant.

The secondary point source which accounts for the remaining particulate matter emissions within a coal gasification plant is the coal handling facilities. The standards of performance promulgated for coal preparation plants (40 CFR Part 60, §§60.250-60.254), however, will limit emissions of

particulate matter from these facilities in any new coal gasification plant. Consequently, standards of performance limiting emissions of particulate matter, NO_x , and about one-third of the uncontrolled sulfur compound emissions from coal gasification plants already exist. Thus, only emissions of non-methane hydrocarbons, carbon monoxide, and the remaining two-thirds of the uncontrolled emissions of sulfur compounds are not already limited by existing standards.

The emission control technique for reducing emissions of both non-methane hydrocarbons and carbon monoxide is the same--incineration. Since these pollutants are both present in the gas streams discharged from coal gasification plants, control of one achieves control of the other.

8.1.2 Selection of Affected Facilities

The primary point sources of non-methane hydrocarbons and sulfur compound emissions within Lurgi coal gasification plants are the: coal gasifier lock-hoppers, coal gas purification facilities, by-product recovery gas/liquid separation facilities, and the sour water stripping facilities. These point sources together account for essentially all the non-methane hydrocarbon emissions and the remaining two-thirds of the uncontrolled sulfur compound emissions.

8.2 SELECTION OF EMISSION LIMITS

8.2.1 Selection of Format

A number of different types of emission limits can be selected. Generally, mass limits are more meaningful than concentration limits because mass limits relate directly to the quantity of emissions discharged into the atmosphere. However, enforcement of mass limits is usually more complex due to the need for a material balance of some form requiring process data concerning the

operation of the plant, such as input material flow rates or production flow rates. This data gathering usually requires more testing or monitoring and therefore can be more costly than enforcement of concentration limits. Also, manipulation of this data to put it in terms of the mass limits can lead to error unless the data is processed carefully.

While limits based on concentration do not directly relate to the quantity of emissions, enforcement of concentration limits requires a minimum of data and information, decreasing costs and the chances for error in the interpretation of test data. A major disadvantage associated with concentration limits, however, is that of possible circumvention by dilution of the pollutant being discharged to the atmosphere, lowering the concentration of the pollutant but not the total mass emitted. While the use of dilution as a means of complying with concentration limits should be prohibited, determining when circumvention by dilution is occurring is sometimes extremely difficult.

Selection of the format for limiting emissions of sulfur compounds from Lurgi coal gasification plants is somewhat complex due to the nature of the coal gasification process and the emission control technology. As discussed above, the waste gas streams discharged by a Lurgi coal gasification plant are predominately carbon dioxide (i.e., 50-95 percent CO_2). Essentially all the carbon dioxide produced in the coal gasification process is removed in the coal gas purification facilities and discharged in these waste gas streams. Thus, the volume of waste gas discharged is determined by the quantity of carbon dioxide produced, which, in turn, is a function of the carbon content of the coal gasified and the operating conditions of the coal gasifier. Since the production of carbon dioxide is minimized to maximize production of methane, where SNG is the desired end product, operation of a Lurgi

gasifier is confined to a relatively narrow range and can be considered fixed. The quantity of carbon dioxide produced, therefore, can be directly related to the carbon content of the coal gasified.

Coal carbon content, however, is not a coal parameter which is included in routine coal analysis. Coal heat content or higher heating value (HHV), on the other hand, is an indirect measure of coal carbon content and is a coal parameter which is normally included in routine coal analysis. Carbon dioxide production and hence the volume of waste gases discharged by the coal gas purification facilities, therefore, is a function of the HHV of the coal gasified.

Essentially all the sulfur contained in the coal gasified by a Lurgi coal gasification plant is also contained in the waste gases discharged from the coal gas purification facilities. Coal sulfur content is not related to coal HHV. Thus, the volume of waste gas streams discharged from a Lurgi coal gasification plant designed for a specific SNG production is fixed by the coal HHV, and the quantity of sulfur emissions contained in these gases is fixed by the coal sulfur content.

Hydrogen sulfide will be the predominant sulfur species present in the waste gas streams discharged from a Lurgi SNG coal gasification plant. A small but significant amount of the sulfur, however, will be present as various organic sulfur compounds. The major constituent of these compounds will probably be carbonyl sulfide. Although the emission control technology comprising alternative control systems is very effective in controlling hydrogen sulfide, this technology will not control organic sulfur compounds such as carbonyl sulfide.

This does not mean that organic sulfur compounds will be emitted into the atmosphere, however. Incineration of the waste gas streams, which will

be required to control emissions of non-methane hydrocarbons and convert residual emissions of hydrogen sulfide to sulfur dioxide as discussed earlier, will effectively convert organic sulfur compounds such as carbonyl sulfide to sulfur dioxide.

As a result, for coals of the same HHV, as the coal sulfur content increases, the hydrogen sulfide and carbonyl sulfide content of the waste gas streams treated by the emission control system increases. The volume of gases treated, however, remains essentially the same. Both the concentration and quantity of residual emissions of hydrogen sulfide discharged from the emission control system before incineration also remain the same. The concentration and quantity of emissions of carbonyl sulfide discharged from the emission control system increase, however, resulting in increased emissions of sulfur dioxide from the coal gasification plant.

Likewise, for coals of the same sulfur content, as the HHV of the coal increases, the volume of the waste gas streams increases. The concentration of carbonyl sulfide emissions discharged from the emission control system before incineration decreases, although the quantity of emissions remains the same. The concentration of residual hydrogen sulfide emissions, however, does not decrease, but remains the same. Consequently, the quantity of sulfur dioxide emissions discharged from the coal gasification plant increases.

It is apparent, therefore, that whether a mass or a concentration format is selected, the numerical emission limit must vary depending on the properties of the coal processed. A concentration format would also require development of appropriate reference conditions to prevent circumvention of regulations by dilution.

In weighing the relative merits of concentration emission limits versus mass emission limits, it appears that mass emission limits would actually be

simpler and easier to enforce than concentration emission limits. This is frequently not the case, especially for single point sources discharging a single waste gas stream. A review of the process flow sheets for the first few Lurgi SNG coal gasification plants being considered for construction, however, indicates that there are any number of possibilities for mixing various waste gas streams, many of which would substantially alter the volume and hence the concentration of emissions, but not the mass of emissions released to the atmosphere. Practical enforcement of a uniform concentration emission limit, therefore, would be difficult if not impossible.

Selection of the format limiting emissions of non-methane hydrocarbons is somewhat easier, although the situation is much the same as that discussed above. Unlike the situation discussed above, however, emissions of non-methane hydrocarbons depend only on the coal HHV.

8.2.2. Selection of Numerical Limits

This section will discuss the selection of numerical emission limits based on the alternative emission control systems using a mass format. Normally, numerical emission limits are selected primarily upon the results of emission tests conducted at well controlled facilities. These data are usually supplemented with data from other sources such as vendor guarantees. As discussed previously, however, there are no well controlled Lurgi coal gasification plants currently operating either in the United States or abroad. The numerical emission limit, therefore, must be selected based upon calculations reflecting the expected performance of the alternative emission control systems. This approach is discussed briefly below, with a more complete explanation included in Appendix C-V.

As discussed above, total sulfur emissions from a Lurgi SNG coal gasification plant depend ultimately upon the sulfur content and HHV of the coal gasified, and the organic sulfur content of the raw coal gas after shift conversion. Non-methane hydrocarbon emissions, on the other hand, depend only on the HHV of the coal gasified. Thus, the numerical emission limits selected need to be expressions of the general form:

$$ES = f_1(S_c, HHV_c, S_o)$$

and $EHC = f_2(HHV_c)$

where:

ES = total sulfur emissions.

EHC = non-methane hydrocarbon emissions.

f_1 and f_2 = functions to be determined.

S_c = coal sulfur input.

HHV_c = coal heat input.

S_o = percent of the sulfur present as in the raw coal gas after shift conversion.

To determine the form of these expressions, process flow sheets provided by those companies now planning Lurgi SNG coal gasification plants were used to develop material balances showing the probable composition of the various gas streams within a plant designed to produce 250 billion Btu per day of SNG. Based on thermodynamic equilibrium calculations, it was assumed that 1.8 percent of the sulfur in the raw coal gas following shift conversion would be present as various organic sulfur compounds (primarily carbonyl sulfide), and the remainder of the sulfur would be present as H_2S . Material balances were developed for three cases: a low sulfur coal of 0.4 lb S/MM Btu (pounds of sulfur per million Btu), an intermediate sulfur coal of 1.2 lb S/MM Btu,

and a high sulfur coal of 3.6 lb S/MM Btu. These material balances are included in Appendix C-II. Generally, the gas stream compositions show good agreement with data gathered from the Lurgi coal gasification plant mentioned earlier, which is currently operating in Sasolberg, South Africa.

As discussed in chapter 5, an assessment of the capability of the various emission control techniques comprising alternative emission control system II concluded that the following assumptions could be made regarding their performance:

1. A Stretford sulfur recovery plant will reduce the concentration of H_2S to 100 ppm, but will not reduce the concentration of organic sulfur compounds.
2. A Claus sulfur recovery plant will convert 95 percent of the incoming H_2S to sulfur. In the gases leaving the Claus plant:
 - (a) Outlet organic sulfur = 0.06 (total wet gas volume)
 - (b) Outlet sulfur vapor = 0.06 (total dry gas volume)

In the incinerator, the following assumptions were made: a temperature of 1600°F, 20 percent excess air, and all sulfur oxidized to SO_2 . The addition of tail gas scrubbing will reduce the concentration of SO_2 in the effluent to 250 ppm.

3. Incineration will reduce the concentration of non-methane hydrocarbon to 100 ppm.

With these assumptions and the material balances developed above, emissions from a Lurgi coal gasification plant using each of the alternative emission control systems were calculated.

To determine the relationship between total sulfur emissions, coal sulfur input, and coal HHV input, a graph relating sulfur emissions divided by coal sulfur input to coal HHV input divided by coal sulfur input was developed for

each control system. Each of the three coal sulfur cases contributed a point to this graph. The equation of the "best fitting" curve drawn through these three points was derived, and upon simplification reduces to:

$$ES = 0.70 (S_c)^{0.85} (HHV_c)^{0.15} \quad \text{For System I}$$

$$ES = 0.032 (S_c)^{0.75} (HHV_c)^{0.25} \quad \text{For System II}$$

This expression is based on the assumption that only 1.8 percent of the sulfur in the raw coal gas following shift conversion is present as organic sulfur compounds. The percent conversion of sulfur in the coal to carbonyl sulfide and other organic sulfur compounds can vary independently of the coal-sulfur-content-producing variations in the sulfur emissions from the plant; however, thermodynamic data indicate that the fraction of sulfur present in the raw coal gas following shift conversion is about 1.8 percent. If the organic sulfur content of the raw coal gas differs substantially from this value, obviously some adjustment should be made in the emission limit.

Since all the material balances presented in Appendix C-II are for a Lurgi coal gasification plant producing 250 billion Btu per day of SNG, the coal heat input (HHV_c) is the same for each case. Consequently, a graph relating emissions of non-methane hydrocarbons to coal HHV cannot be developed. To determine the relationship between emissions and coal HHV, therefore, emissions of non-methane hydrocarbons calculated for the moderate coal sulfur case under alternative emission control system II were divided by the coal HHV for this case. This results in a factor by which to multiply the coal HHV to determine emissions. Assuming a linear relationship between coal HHV and emissions of non-methane hydrocarbons yields the following expression:

$$EHC = 0.07 HHV_C$$

where:

EHC = emissions of non-methane hydrocarbons (kg/hr).

HHV_C = coal heat input MW.

This expression is selected as the numerical emission limit for non-methane hydrocarbon emissions.

As mentioned earlier and is evident by the above discussion, these numerical emission limits are based solely upon calculations which are totally dependent upon the assumptions made concerning the anticipated performance of the alternative emission control systems. Due to the technological uncertainties inherent in such a "transfer-of-technology" approach, it is quite clear that this could result in regulations which are overly stringent. Accordingly, some margin of leniency should be applied to the equations derived for sulfur and hydrocarbon emissions before emission limitations are set.

8.3 SELECTION OF PERFORMANCE TEST METHODS AND EMISSION MONITORING REQUIREMENTS

Compliance is normally demonstrated by a performance test to determine emissions, although in certain cases other procedures can be employed to demonstrate compliance. Also, emission monitoring requirements are normally included as an aid to enforcement personnel in ensuring proper operation and maintenance on a continuing basis of the emission control systems installed to comply with the regulations. At this time, however, neither reference methods to determine emissions nor performance specifications for continuous monitors to monitor emissions from Lurgi coal gasification plants have been developed.

While the absence of reference test methods and emission monitoring requirements could present practical problems to enforcement of regulations if a commercial Lurgi coal gasification plant were to start operation before they became available, this is not likely to occur. Work is currently underway to develop reference test methods and specifications for continuous emission monitors applicable to coal gasification plants. In light of the fact that construction of these plants is likely to require two to three years, reference test methods and performance specifications for continuous monitors will undoubtedly be available by the time they are needed. In any event, if the need arises, as pointed out above, procedures other than performance tests can be employed to determine compliance with regulations.

With regard to eventual selection of continuous emission monitoring requirements, as mentioned above, the objective of these requirements is to provide a means for enforcement personnel to ensure that the emission control system is properly operated and maintained on a continuing basis. Monitoring emissions released to the atmosphere from each of the facilities affected by the standards would accomplish this objective, but would require installation of a large, complex, and costly monitoring system. As discussed earlier, the coal gas purification facilities are the major point source of uncontrolled sulfur and non-methane hydrocarbon emissions. Thus, monitoring emissions from these facilities would, to a large extent, accomplish the same objective as monitoring emissions from each of the affected facilities. Also, such a monitoring system would be much less complex and costly.

8.4 ENFORCEMENT CONSIDERATIONS

The numerical emission limits recommended above are equations which relate emissions to various operating parameters, such as coal heat input, coal sulfur input, and the percentage of sulfur present as organic sulfur in the raw coal gas following shift conversion. Determining compliance, therefore, would require not only measuring emissions, but also measuring these operating parameters.

With regard to emissions of sulfur compounds, this should be relatively straightforward. Emissions of sulfur compounds from the coal gasifier lock hoppers, coal gas purification facilities, sour water stripping facilities, and the by-product recovery gas/liquid separation facilities would be determined and added together. Coal sulfur input and coal heat input (based on higher heating value) to the gasifiers and the percentage of sulfur present as organic sulfur compounds following shift conversion would then be determined. Next, the numerical emission limit would be determined using the equation selected above. Comparison of actual emissions with the calculated allowable numerical emission limit would determine whether the source was in compliance.

Complications could arise, however, in those situations where the gas streams from the affected facilities were added to gas streams from other facilities, such as a power plant, or processed by other facilities, such as an incinerator, which increase the sulfur content of the resulting gas stream discharged to the atmosphere. The numeric 1 emission limit for sulfur compounds was selected on the basis of limiting emissions from only the coal gasifier lock hoppers, coal gas purification facilities, by-product recovery gas/liquid separation facilities, and the sour water stripping facilities. Consequently, the effect of sulfur emissions due to other facilities, such as power plants or incinerators, would first have to be subtracted from the measurement of sulfur emissions discharged to the atmosphere, or added to the allowable emissions determined by the numerical emission limit equation before compliance could be determined.

With regard to emissions of non-methane hydrocarbons, determining compliance should also be relatively straightforward. As above, emissions of non-methane hydrocarbons from the coal gasifier lock hoppers, coal gas purification facilities, by-product recovery gas/liquid separation facilities, and the sour water stripping facilities would be determined and added together. Coal heat input (based on the higher heating value) to the gasifiers would then be determined and the numerical emission limit calculated using the equation selected above. Comparison of actual emissions with the calculated allowable numerical emission limit would determine whether the source was in compliance.

The complication discussed above concerning sulfur emissions is not likely to arise with non-methane hydrocarbon emissions. Another complication, however, is likely to arise, that of determining emissions of non-methane hydrocarbons following flaring. Currently, no method exists for measuring emissions following flaring, but a number of experimental techniques are under development.

8.5 REFERENCES

1. Priorities and Procedures for Development of Standards of Performance for New Stationary Sources of Atmospheric Emissions, Prepared for Environmental Protection Agency, Office of Air and Waste Management, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., by Argonne National Laboratory, EPA-450/3-76-020, May 1976.
2. Air Quality Criteria for Particulate Matter (AP-49), Sulfur Oxides (AP-50), Carbon Monoxide (AP-62), Photochemical Oxidants (AP-63), Hydrocarbons (AP-64), and Nitrogen Oxides (AP-84), U.S. Department of Health, Education and Welfare, Public Health Service, National Air Pollution Control Administration.

3. **Impact of Energy Resource Development on Reactive Air Pollutants in the Western United States, Final Report, Volume 1 - Executive Summary, Prepared for Environmental Protection Agency, Office of Planning and Evaluation, Washington, D.C., by Environmental Research & Technology, Inc., under Contract No. 68-01-2801, February 1976.**

Appendix C-1 Emission Test Data

INTRODUCTION

This appendix summarizes engineering and emission test data used as a basis for developing this document on emission control systems for coal gasification plants. Information on each facility is also presented herein. Each facility is identified by the same coding used in Chapter 4. Any reference in this appendix to commercial products or processes by name does not constitute an endorsement by the Environmental Protection Agency.

SUMMARY OF DATA

Estimates and actual operating data on Lurgi-Rectisol, Rectisol, and ADIP processes; operating data on Stretford and Claus sulfur recovery in other industries; emission data for Wellman-Lord and Beavon processes for SO_2 and H_2S removal from tail gases; and emission data for hydrocarbon and carbon monoxide combustion in carbon black CO boilers are presented herein. From these data and engineering estimates, the operation of sulfur, hydrocarbon, and carbon monoxide emission control technologies on expected Lurgi-Rectisol gas streams are calculated in Appendix C-2. EPA test data for Claus plants, incinerators, tail gas treating, and CO boilers were taken from previous EPA studies to develop standards of performance in petroleum refining, oil and gas production, and furnace carbon black production. EPA measurements include total sulfur (H_2S , SO_2 , COS , CS_2) by

EPA Method 18, SO_2 by EPA-6, H_2S by EPA-11, CO by EPA-10, NO_x by EPA-7, Orsat gases by EPA-3, and moisture by EPA-4. Hydrocarbons, for which there is no EPA method to date, were measured by flame ionization detection (FID), except where noted.

DESCRIPTION OF FACILITIES

Plant CG-1 is an overseas gasification plant consisting of 13 Lurgi gasifiers and a common Rectisol sulfur removal system. The plant consumes 6700 metric tons per day coal in the Lurgi gasifiers. Coal would be classed as subbituminous C, similar to coals to be gasified in New Mexico and Wyoming. Sulfur-heating value ratio of coal is $0.51 \text{ lb S}/10^6 \text{ Btu}$. Plant production is 936,000 normal cubic meters (NCM) per day of raw synthesis gas for production of liquid hydrocarbons.

The Rectisol wash has three distinct wash and regeneration sections with three off-gas streams as shown in Table C-1.1.

Plant CG-2 represents the pilot data for a proposed $250 \times 10^9 \text{ Btu/day}$ Lurgi-Rectisol gasification plant obtained from plant R-1 when gasifying a lignite coal. The coal gasified has an average sulfur-heating value ratio of $1.20 \text{ lb sulfur}/10^6 \text{ Btu}$.

Plant R-1 is a partial oxidation-hydrogen plant used by a U.S. refinery to produce hydrogen via gasification of fuel oil. The plant produces $25.5 \times 10^6 \text{ scfm/day}$ of hydrogen and carbon monoxide. A Rectisol unit removes acid gases and regenerates two streams - a large CO_2 -rich stream and a small H_2S -rich stream. The H_2S stream is treated with other refinery acid gases in a Claus-Beavon sulfur removal system. Gas stream compositions, temperatures, and pressures are shown in Table C-1.3.

Plant S-1 is a foreign coking operation which uses a Stretford system (preceded by a wash to remove hydrogen cyanide) to remove hydrogen sulfide from approximately 750,000 normal cubic meters per day (ncm/d) from coke oven gas. Sulfur removal is normally 3 tons per day. Product gas is then compressed and injected into a low-Btu gas pipeline. Gas stream data are presented in Table C-1.4.

Plant C-1 is a domestic natural gas processing plant which has a Claus unit recovering sulfur from amine off-gases containing about 80 mole percent H_2S . Plant C-2 is a neighboring gas plant to C-1 which has a Claus unit recovering sulfur from amine off-gases containing only 20 mole percent H_2S . Tables C-1.5 and C-1.6 show comparative gas stream data, which illustrate the ability of modern Claus technology to recover sulfur from widely varying sulfur feed streams. An EPA emission test was also conducted in plant C-1 and is also summarized in Table C-1.6. Both Claus plants C-1 and C-2 are three-stage operations, plant C-1 uses a "straight-through" Claus process, while plant C-2 uses a "split-flow" process.

For tail gas sulfur removal, plants TG-1 and TG-2 (Tables C-1.7 through C-1.9) are typical of well-controlled Claus plants in petroleum refineries. Plant TG-1 consists of three 150 LT/D Claus plants followed by a single Wellman-Lord SO_2 removal process. Plant TG-2 has a single 100 LT/D Claus plant followed by a Beavon process.

Facilities TG-2(a) and TG-2(b) (Tables C-1.8 and 1.9) represent plant emission data obtained by EPA and plant personnel, respectively, at plant 2 using different test procedures. These data quantify the emissions to be expected from a reduction-based sulfur recovery scheme. For the oxidation-based sulfur recovery, EPA emission data for plant TG-1 (Table C-1.7) demonstrates the capability of a well-operated SO_2 scrubber on acid gases.

Tables C-1.10 and C-1.11 show the EPA emission data for two carbon monoxide boilers burning gases from furnace carbon black production. Plant A boiler produces 45,000 lb/hr of 400 psig, 650°F steam, while plant C boiler produces 50,000 lb/hr of 260 psig steam. Inlet and outlet hydrocarbons (acetylene and methane) and carbon monoxide are shown in Tables C-1.10 and 1.11. Total hydrocarbon and CO loading is more severe than that projected in coal gasification acid gases.

GLOSSARY FOR APPENDIX C-1

psig	lbs per square inch gauge
m^3_n/h	normal cubic meters per hour
mg/m^3_n	milligrams per normal cubic meter
ppm	parts per million (by volume unless otherwise stated)
N.D.	not detectable
NA	no data available
mscf	thousand standard cubic feet
scfm	standard cubic feet per minute
DNm^3/m	dry normal cubic meters per minute
kw	kilowatt
mmKcal/hr	million kilocalories per hour
mm	millimeters

Table C-1.1
Facility CG-1
Lurgi-Rectisol Feed and Off-gas Characterization - Operating Data

Component	Rectisol Feed Gas	Product Gas	Off-Gases			Units
			HP* Flash Gas	LP** Flash Gas	Atm Flash Gas	
H ₂	40.05	57.30	21.4	2.6	0.14	mol %
CO	20.20	28.40	18.2	4.8	0.0	mol %
CH ₄	8.84	11.38	11.4	7.2	0.9	mol %
CO ₂	28.78	0.93	46.7	83.4	97.2	mol %
N ₂ +A	1.59	1.77	1.5	0.8	0.03	mol %
H ₂ S	(4220 mg/m ³ _n)	N.D.	(4500 mg/m ³ _n)	(7000 mg/m ³ _n)	(12500 mg/m ³ _n)	mol %
COS	(10 ppm)	NA	NA	NA	0.003	mol %
CS ₂	NA	NA	NA	NA	0.0002	mol %
RSH	(20 ppm)	NA	NA	NA	0.028	mol %
Thiophene	NA	NA	NA	NA	0.0002	mol %
Total Sulfur	NA	(0.05 mg/m ³ _n)	NA	NA	NA	mol %
C ₂ ⁺	0.54	-	0.7	1.1	0.7	mol %
Temperature	30	15	0	0	-5	°C
Pressure	365	330	180	55	1	psig
Flow Rate	381,000	263,000	4,600	15,000	98,000	m ³ _n /h

*HP - High Pressure

**LP - Low Pressure

Reference: Trip Report, "Visits at the South African Coal, Oil, and Gas Corporation, Limited and the AE & CI Limited Coal Gasification Plants, W. O. Herring, ESED, OAQPS, EPA, dated Feb. 4, 1975.

Table C-1.2

Facility CG-2
Estimated Coal to SNG Plant Off-gas Compositions - Pilot Data

Component	CO ₂ Vent Gas	CO ₂ Flash Gas	H ₂ S Flash Gas	Hot Regenerator Gas	Pretreat Vent Gas	Expasion Gas	ADIP Vent Gas	ADIP Regenerator Gas	Phenoluan Acid Gas
CH ₄	21.6	54.8	167.5			29.5			
C ₂ H ₆	21.3	46.1	74.6	126.5	2.8		126.5		
C ₃ H ₈	2.3	4.3	17.6	55.5			55.5		
C ₄ H ₁₀			2.4	28.2			28.2		
CO ₂	5683.5	14350.9	18528.8	1393.4	83.2	221.0	1329.0	64.5	360.8
CO						44.1			
H ₂						93.7			
H ₂ S	0.1	0.22	175.4	365.8	17.14	0.1	0.4	365.4	22.6
N ₂									
O ₂									
H ₂ O				40.5					
SO ₂						21.8	77.6	40.7	5.9
NH ₃									
COS	0.1	0.2	2.7	2.7	0.1		2.7		
HCN					1.4				
C ₂ H ₄	4.2	10.8	6.7	0.1			0.1		
C ₃ H ₆	0.9	3.2	12.5	31.6			31.6		
C ₄ H ₈			1.3	25.6			25.6		
CH ₃ OH	1.7	4.9	7.3	-					

(All Numbers in lb mole/hr.)

Reference: American Gas Association/EPA meeting, Durham, N.C., January 6, 1977.

Table C-1.3
Facility R-1
Rectisol Operating Data in Oil Gasification Application

Component	Rectisol Feed Gas	Product Gas	Off-Gases		Units
			lean H ₂ S	rich H ₂ S	
H ₂	63.74	93.58	0.33	NA	mol %
CO	4.13	6.06	0.14	NA	mol %
CH ₄	0.13	0.19	0.00	NA	mol %
CO ₂	31.62	NA	80.19	68.46	mol %
N ₂ +A	0.12	0.17	19.34**	NA	mol %
H ₂ S	0.26	NA	(<5 ppm)	30.78	mol %
COS	(63 ppm)	NA	(8 ppm)	0.76	mol %
CS ₂	NA	NA	NA	NA	mol %
RSH	NA	NA	NA	NA	mol %
Thiophene	NA	NA	NA	NA	mol %
C ₂ ⁺	NA	NA	NA	NA	mol %
Temperature	86	72	72	121	°F
Pressure	30	425	0.8	58	lb/in ² gauge
Flow Rate	2976	2027	1145	25	mscf/hr*

* At 60°F, 1 atm pressure

** 223 mscf/m N₂ used as stripping gas

Reference: Letter, G. A. Collins, Jr., Texaco, Inc. to Don R. Goodwin,
ESED, OAQPS, EPA, dated June 16, 1975.

Table C-1.4
Plant S-1
Stretford Operating Data - Coke Oven Gas

<u>Month Averaged</u>	<u>Conc. in Feed to Wash Section, g/m³*</u>		<u>Conc. in Feed to Stretford, g/m³*</u>		<u>Conc. in Product Gas, g/m³*</u>	
	<u>H₂S</u>	<u>HCN</u>	<u>H₂S</u>	<u>HCN</u>	<u>H₂S</u>	<u>HCN</u>
Dec. '74	5.70	0.87	5.15	0.15	Not detectable	
Jan. '75	5.65	0.81	5.14	0.24	Not detectable	
Feb. '75	5.58	0.91	4.90	0.24	Not detectable	
Mar. '75	5.53	0.92	4.85	0.24	Not detectable	

*grams/standard cubic meter.

REFERENCE: Trip Report - "Visits at the Gottfried Bischoff Company, the Ruhrkohlen Coke Plant and the Westfield Development Center," W. O. Herring, ESED, OAQPS, EPA, July 2, 1975.

Table C-1.5
Plant C-1
Claus Performance - Natural Gas Acid Gases
Claus
Incinerator Outlet

<u>Component</u>	<u>Acid Gas</u>	<u>Incinerator Outlet</u>	
H ₂ S	81.13	(27.5 ppm)	
SO ₂	-	0.672	
COS	0.01	(19.7 ppm)	
CS ₂	-	(15.0 ppm)	% sulfur recovery
CO ₂	18.09	9.5	= $\frac{.8113(2158) - .006797(5663)}{.8113(2158)}$
N ₂	0.14	N/A	= 97.8%
O ₂	-	4.7	
C ₁	0.27		
C ₂	0.09	625 ppmv	
C ₃ ⁺	0.27		
Flow, scfm(dry)	2158.0	5663.0	

(All numbers in mole % where units not indicated.)

Reference: EPA Source Test Report No. 75-SR4-9, Scott Environmental Technology, Inc., Plumsteadville, Pa., January 1976.

Table C-1.6
Plant C-2
Split-Flow Claus Performance - Natural Gas Acid Gases

Component	Claus Feed	Claus Tail Gas	Incinerator Outlet	
COS	-	0.09	-	
H ₂ S	19.72	0.26	trace	
SO ₂	-	0.10	0.40	
H ₂ O	— dry analysis basis —			
CO ₂	78.68	65.04	25.31	
N ₂	0.56	34.34	74.64	
S ₂	-	-	-	% sulfur recovery
O ₂	-	-	-	= $\frac{.1972(19273) - .0045(28480)}{.1972(19273)} \times 100$
C ₁	0.66	-	-	= 96.9%
C ₂	0.12	0.19	0.1	
C ₃	0.08	0.03	-	
C ₄	0.18	-	-	
C ₅ ⁺	-	-	-	
Temp. °F	104	275	990	
Press. (psig)	8.1	0.4	0.1	
Flow, (wet basis) mcf/d	19,273	28,480	37,920	

(All numbers in mole % where units not indicated.)

Reference: Letter, A. N. Crownover, Jr., Exxon Company, USA, to Don R. Goodwin, ESED, OAQPS, EPA, dated Nov. 20, 1975.

Table C-1.7
Wellman-Lord Performance on Claus Tail Gases
Facility TG-1
Summary of Results

Run Number	1	2	3	Average
Date	3/11/74	3/12/74	3/13/74	
Stack Effluent:				
Flow rate - DNM ³ /min	197.1	135.4	209.7	180.4
Water vapor - Vol. %	13.0	10.5	11.2	11.6
CO ₂ - Vol. % dry ^a	-	7.2	5.35	6.3
O ₂ - Vol. % dry ^a	-	0.8	2.95	1.9
CO - Vol. % dry ^a	-	0.0	0.0	0.0
CO ₂ - Vol. % dry ^b	4.3	5.6	3.8	4.6
O ₂ - Vol. % dry ^b	0.9	0.2	1.5	0.9
CO - ppmv dry ^b	95	100	39	78
SO ₂ - ppmv dry ^c	5.9	21.8	7.4	11.7
SO ₂ - ppmv dry ^d	38	16	10	21
COS - ppmv dry ^d	3.2	1.9	0.9	2.0
CS ₂ - ppmv dry ^d	2.5	3.4	1.1	2.3
H ₂ S - ppmv dry ^d	<0.1	<0.1	<0.1	<0.1
TS - ppmv dry ^d	46.2	24.7	13.1	28.0
NO _x - ppmv dry ^e	17.2	9.0	21.0	15.7
THC - ppmv dry ^f	7.5	6.2	4.6	6.1
Visible emissions ^g	0	0	0	0

^aOrsat analysis

^bNDIR/Paramagnetic

^cEPA-6

^dGC/FPD (EPA-18)

^eEPA-7

^fTotal hydrocarbons as methane by flame ionization

^gEPA-9

Reference: Source Test Report No. 74-SRY-1, EPA Contract No. 68-02-0232, Task Order No. 34, Environmental Science and Engineering, Gainesville, Fla., March 1974.

Table C-1.8
Beavon Performance on Claus Tail Gases
Facility TG-2(a)
Summary of Results

Run Number	1	2	3	Average
Date	3/05/74	3/06/74	3/07/74	
Stack Effluent:				
Flow rate, DNM ³ /M	65.5	71.6	68.8	68.6
Water vapor - Vol. %	4.2	5.0	3.3	4.2
CO ₂ - Vol. % dry ^a	5.4	5.5	6.0	5.6
O ₂ - Vol. % dry ^a	0.6	0.5	0.3	0.5
CO - Vol. % dry ^a	0	0	0	0
CO ₂ - Vol. % dry ^b	5.8	5.7	5.9	5.8
O ₂ - Vol. % dry ^b	0.02	0.09	0.02	0.04
CO - Vol. % dry ^b	566	565	604	578
SO ₂ - ppmv dry ^c	3.6	3.8	4.5	4.0
SO ₂ - ppmv dry ^d	1.5	0.7	0.76	1.0
COS - ppmv dry ^d	17	17	15	16
CS ₂ - ppmv dry ^d	0.15	-	-	-
H ₂ S - ppmv dry ^d	0.1	0.1	0.1	0.1
TS - ppmv dry ^d	19	17	16	17
NO _x - ppmv dry ^e	1.1	0	0	0.4
THC - ppmv dry ^f	-	-	-	-
Visible emissions ^g	0	0	0	0

^aOrsat analysis

^bNDIR/Paramagnetic

^cEPA-6

^dGC/FPD (EPA-18)

^eEPA-7

^fTotal hydrocarbons as methane by flame ionization

^gEPA-9

Reference: Source Test Report No. 74-SRY-2, EPA Contract No. 68-02-0232, Task Order No. 34, Environmental Science and Engineering, Gainesville, Fla., March 1974.

Table C-1.9
Beavon Performance on Claus Tail Gases
Facility TG-2(b)

Summary of Results

Run Number	1	2	3
Date	3/5/74	3/6/74	3/7/74
Stack Effluent:			
Flow rate - DNM ³ /M	-	-	-
COS - ppm dry	9	9	9
CS ₂ - ppm dry	0	0	0
H ₂ S - ppm dry	7	1	0
SO ₂ - ppm dry	0	0	5
Total sulfur - ppm dry	16	10	14
CO - ppm dry	479	620	595
H ₂ , mol %	5.0	6.0	5.8
THC as (CH ₄), ppm	125	206	332
N ₂ , mol %	87.7	87.0	86.9
O ₂ , mol %	0	0	0
A , mol %	1.0	1.0	1.0

Reference: Letter, George L. Tilley, Union Oil Company of California, to
C. Sedman, ESED, OAQPS, EPA, Dated August 26, 1974.

Table C-1.10
Carbon Monoxide Emission Data From Carbon Black CO Boilers

<u>Plant</u>	<u>Average inlet CO concentration, %</u>	<u>Average outlet CO concentration, ppmv</u>
A (test 1)	11.2	N.D.
	6.5	N.D.
	13.4	N.D.
	13.4	N.D.
A (test 2)	N.D.	128
	N.D.	123
	N.D.	120
C	12.4	28
	12.3	62
	12.3	57

Reference: Standards Support and Environmental Impact Statement - "An Investigation of the Best Systems of Emission Reduction for Furnace Process Carbon Black Plants in the Carbon Black Industry" - U. S. EPA, OAQPS, ESED, Research Triangle Park, North Carolina 27711, April 1976, pp. C-14 thru C-20.

Table C-1.11
Hydrocarbon Emission Data From Carbon Black CO Boilers

<u>Plant</u>	<u>Average inlet concentration, ppmv</u>	<u>Average outlet concentration, ppmv</u>
A (test 1)	N.D.	125
	10,000	45
	10,000	60
C	12,000	N.D.
	11,000	N.D.

Reference: Standards Support and Environmental Impact Statement - "An Investigation of the Best Systems of Emission Reduction for Furnace Process Carbon Black Plants in the Carbon Black Industry" - U. S. EPA, OAQPS, ESED, Research Triangle Park, North Carolina 27711, April 1976, pp. C-14 thru C-20.

APPENDIX C-II

MATERIAL AND ENERGY BALANCE CALCULATIONS TO QUANTIFY THE ALTERNATIVE EMISSION CONTROL SYSTEMS

Based on the alternative emission control systems outlined in Chapter 5, pilot gasification data from Table C-1.2, and the expected performance of emission control systems in Appendix C-1; emissions, energy consumption, and waste streams were calculated as follows:

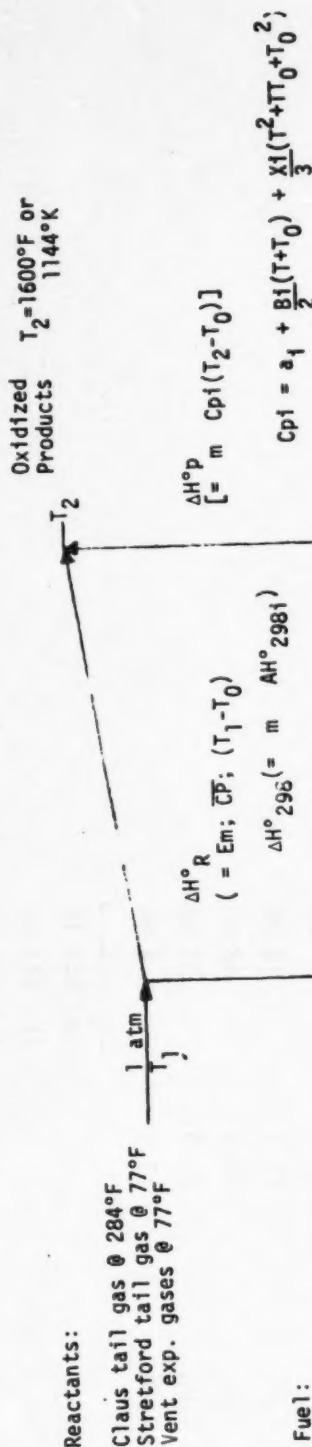
BASIS: SNG Product @ 250×10^9 Btu/Day
Feedstock selection based on high and low extremes of sulfur/heating value ratio:

(a) Low extreme is $\left[\frac{0.4 \text{ lb S}}{10^6 \text{ Btu}} \right]$

(b) Middle case is $\left[\frac{1.2 \text{ lb S}}{10^6 \text{ Btu}} \right]$

(c) High extreme is $\left[\frac{3.6 \text{ lb S}}{10^6 \text{ Btu}} \right]$

Basis for Incineration Calculations



Component $\overline{Cp}(T=284^{\circ}\text{F})$ $\overline{Cp}(T=1600^{\circ}\text{F})$

CO	6.99	-
H ₂	6.94	-
CH ₄	9.25	-
C ₂ H ₄	11.89	-
C ₂ H ₆	14.42	-
N ₂	6.97	8.14
CO ₂	9.29	13.04
H ₂ S	8.38	-
COS	10.62	-
SO ₂	11.76	12.87
H ₂ O	8.11	10.77
O ₂	-	8.44
CS ₂	11.95	-
S	10.82	-

$\Delta H^{\circ}_{298} = 121,744.8 \text{ Btu/lb-mole}$
 $\Delta H^{\circ}_{298} = 104,026.4$
 $\Delta H^{\circ}_{298} = 345,135.6$
 $\Delta H^{\circ}_{298} = 569,109.6$
 $\Delta H^{\circ}_{298} = 614,309.4$
 $\Delta H^{\circ}_{298} = 233,097.4$
 $\Delta H^{\circ}_{298} = 237,981.6$
 $\Delta H^{\circ}_{298} = 955,080.0$
 $\Delta H^{\circ}_{298} = 1237,752.0$
 $\Delta H^{\circ}_{298} = 885,582.0$
 $\Delta H^{\circ}_{298} = 1169,010.0$
 $\Delta H^{\circ}_{298} = 290,786.4$
 $\Delta H^{\circ}_{298} = 127,728.0$

Reactions:

- CO + 1/2 O₂ → CO₂
- H₂ + 1/2 O₂ → H₂O (g)
- CH₄ + 2O₂ → CO₂ + 2H₂O (g)
- C₂H₄ + 3O₂ → 2CO₂ + 2H₂O (g)
- C₂H₆ + 7/2 O₂ → 2CO₂ + 3H₂O (g)
- H₂S + 3/2 O₂ → H₂O (g) + SO₂
- COS + 3/2 O₂ → CO₂ + SO₂
- C₃H₈ + 5O₂ → 3CO₂ + 4H₂O (g)
- C₄H₁₀ + 13/2 O₂ → 4CO₂ + 5H₂O (g)
- C₃H₆ + 9/2 O₂ → 3CO₂ + 3H₂O (g)
- C₄H₈ + 6O₂ → 4CO₂ + 4H₂O (g)
- CH₃OH + 3/2 O₂ → CO₂ + 2H₂O (g)
- S + O₂ → SO₂

Air/Fuel Requirements: Required CH₄ = x lb-moles/hr
 O₂ = 1.2[1/2 (CO) + 1/2 (H₂) + 2 (CH₄) + 3 (C₂H₄) + 7/2 (C₂H₆) + 5 (C₃H₈) + 13/2 (C₄H₁₀) + 9/2 (C₃H₆) + 6 (C₄H₈) + 3/2 (CH₃OH) + 3/2 (H₂S + COS)]

N₂ = 79/21 O₂

Assuming fuel gas is 970 BTU/SCF as CH₄, $x = \Delta H^{\circ}_p - \Delta H^{\circ}_R$ = $\Delta H^{\circ}_p - \Delta H^{\circ}_R$
 (970 BTU/SCF)(386.7 SCF/lb-mole) 3.75 x 10⁵ BTU/lb-mole

Uncontrolled Case

Component	$\dot{m}$ in lb-mole/hr	ΔH_C BTU x 10 ⁶	Component	$\dot{m}$ out lb-mole/hr	ΔH_R BTU x 10 ⁶	Incinerator exhaust lb-mole/hr
CH ₄	273.4	94.36	CO ₂	(a) 42155.7 + x (b) 42163.2 + x (c) 42184.2 + x	837.21 837.36 837.78	44740.0 44523.4 43880.8
C ₂ H ₆	271.3	166.66	N ₂	(a) 13006.0 + 9.03x (b) 15768.8 + 9.03x (c) 23547.6 + 9.03x	161.24 195.49 291.93	36342.2 37081.4 38863.4
C ₃ H ₈	79.8	76.22	O ₂	(a) 576.2 + 0.4x (b) 698.6 + 0.4x (c) 1043.3 + 0.4x	7.40 8.97 13.40	11609.9 1642.7 1721.7
C ₄ H ₁₀	30.6	37.88	H ₂ O	(a) 2646.5 + 2x (b) 3054.5 + 2x (c) 4203.3 + 2x	43.41 50.10 68.95	7815.1 7774.9 7595.5
CO ₂	40,621.6	-	SO ₂	(a) 169.4 (b) 584.9 (c) 1754.7	3.29 11.36 34.08	169.4 584.9 1754.7
CO	44.1	5.37				
H ₂	93.7	9.75				
H ₂ S	(a) 166.4 (b) 574.4 (c) 1723.2	38.79 133.89 408.57				
N ₂	-	-				
O ₂	-	-				
H ₂ O	68.2	-				
SO ₂	-	-				
COS	(a) 3.0 (b) 10.5 (c) 31.5	0.71 2.50 7.50				
C ₂ H ₄	21.7	12.35				
C ₃ H ₆	48.1	42.60				
C ₄ H ₈	26.9	31.45				
CH ₃ OH	13.9	4.04				
		(a) 520.18 (b) 617.07 (c) 896.75			(a) 1052.55 (b) 1103.28 (c) 1246.14	90676.6 91607.3 93816.1

Uncontrolled Case (continued)

$$x_a = \frac{1052.55 - 520.18}{.206} = 2584.3$$

$$\text{heat required} = 969.1 \times 10^6 \text{ BTU/hr}$$

$$x_b = \frac{1103.28 - 617.07}{.206} = 2360.2$$

$$\text{heat required} = 885.1 \times 10^6 \text{ BTU/hr}$$

$$x_c = \frac{1246.14 - 896.75}{.206} = 1696.1$$

$$\text{heat required} = 636.0 \times 10^6 \text{ BTU/hr}$$

$$\begin{aligned} \text{(a) } O_2 \text{ required} &= 3165.3 + 1.8 (166.4 - 4.2) + 2.4x = 3457.3 + 2.4x \\ \text{(b) } O_2 \text{ required} &= 3165.3 + 1.8 (574.4 - 4.2) + 2.4x = 4191.7 + 2.4x \\ \text{(c) } O_2 \text{ required} &= 3165.3 + 1.8 (1723.2 - 4.2) + 2.4x = 6259.5 + 2.4x \end{aligned}$$

$$\begin{aligned} \text{(a) } N_2 \text{ required} &= 13006.0 + 9.03x \\ \text{(b) } N_2 \text{ required} &= 15768.8 + 9.03x \\ \text{(c) } N_2 \text{ required} &= 23547.6 + 9.03x \end{aligned}$$

$$\begin{aligned} \text{(a) } H_2O \text{ produced} &= 2484.3 + 2x + (166.4 - 4.2) = 2646.5 \\ \text{(b) } H_2O \text{ produced} &= 2484.3 + 2x + (574.4 - 4.2) = 3054.5 \\ \text{(c) } H_2O \text{ produced} &= 2484.3 + 2x + (1723.2 - 4.2) = 4203.3 \end{aligned}$$

$$\begin{aligned} \text{(a) } CO_2 \text{ produced} &= 42155.7 + x \\ \text{(b) } CO_2 \text{ produced} &= 42163.2 + x \\ \text{(c) } CO_2 \text{ produced} &= 42184.2 + x \end{aligned}$$

System I(a)

Component	Stretford Feed lb-mole/hr	ADIP Feed lb-mole/hr	ADIP Vent to Incinerator lb-mole/hr	Claus Feed (Vent + ADIP) lb-mole/hr	Stretford Exhaust lb-mole/hr	Claus Exhaust lb-mole/hr	Incinerated Stretford Exhaust lb-mole/hr	Incinerated Claus Exhaust lb-mole/hr
CH ₄	273.4				273.4		-	-
C ₂ H ₆	142.0	126.5	126.5	2.8	142.0		-	-
C ₃ H ₈	24.3	55.5	55.5		24.3		-	-
C ₄ H ₁₀	2.4	28.2	28.2		2.4		-	-
CO ₂	38784.2	1393.4	1329.0	147.7	38784.2	153.1	44259.8	190.5
CO	44.1				44.1		-	-
H ₂	93.7				93.7		-	-
H ₂ S	56.6	104.9	0.4	109.4	3.9	4.5	-	-
N ₂						242.6	35515.5	608.5
O ₂		40.5	77.6	40.7		0.1	1573.2	16.1
H ₂ O						154.0	7722.0	232.7
SO ₂						2.3	7.1	7.3
CO _S	1.5	1.4	1.3	0.1	1.5	0.3		
C ₂ H ₄	21.6	0.1	0.1		21.7			
C ₃ H ₆	16.5	31.6	31.6		16.5			
C ₄ H ₈	1.3	25.6	25.6		1.3			
CH ₃ OH	13.9				13.9			
S vapor						0.2		
Total	39475.7.	1807.7	1675.8	300.7	39423.0	527.1	89077.6	1055.1

System I(a) (continued)

Stretford Incinerator Calculations

$$\begin{aligned}\Delta H_C &= 482.32 - .09 = 482.23 \\ \Delta H_P &= 1022.81 + .169x = 1021.69 + .169x \\ x &= \frac{1021.69 - 482.23}{.206} = 2618.3 \text{ lb-mole CH}_4/\text{hr}\end{aligned}$$

$$\text{Heat requirement} = 981.8 \times 10^6 \text{ BTU/hr}$$

$$\begin{aligned}\text{CO}_2 &= 41641.5 + x = 44259.8 \\ \text{H}_2\text{O} &= 2485.4 + 2x = 7722.0 \\ \text{O}_2 &= 525.9 + 0.4x = 1573.2 \\ \text{N}_2 &= 11872.2 + 9.03x = 35515.4 \\ \text{SO}_2 &= 7.1\end{aligned}$$

Claus Incinerator Calculations

	$\frac{\Delta H_R}{\Delta H_C}$	$\frac{\Delta H_P}{\Delta H_C}$	Fuel composition
CO ₂	2.95	30.46 + 0.20x	153.4 + x
H ₂ S	0.08	-	-
N ₂	3.50	33.57 + 1.12x	270.8 + 9.03x
O ₂	.00	0.17 + 0.05x	1.3 + 0.4x
H ₂ O	2.59	26.00 + 0.33x	158.5 + 2x
SO ₂	.05	1.43	7.3
COS	-	0.71	-
S	-	0.26	-
	9.17	11.46	96.63 + 1.70x

$$x = \frac{96.63 - 11.46 - 9.17}{2.05} = 37.1 \text{ lb-mole CH}_4/\text{hr}$$

$$= 13.9 \times 10^6 \text{ BTU/hr}$$

System I(b)

Component	Stretford Feed lb-mole/hr	ADIP Feed lb-mole/hr	ADIP Vent to Incinerator lb-mole/hr	Claus Feed (Vent + ADIP) lb-mole/hr	Stretford Exhaust lb-mole/hr	Claus Exhaust lb-mole/hr	Incinerated Stretford Exhaust lb-mole/hr	Incinerated Claus Exhaust lb-mole/hr
CH ₄	273.4				273.4			
C ₂ H ₆	142.0	126.5	126.5	2.8	142.0			
C ₃ H ₈	24.3	55.5	55.5		24.3			
C ₄ H ₁₀	2.4	28.2	28.2		2.4			
CO ₂	38784.2	1393.4	1329.0	147.7	38784.2	152.7	44272.7	229.7
CO	44.1				44.1			
H ₂	93.7				93.7			
H ₂ S	195.8	362.9	0.4	379.2	3.9	12.6		
N ₂						750.1	35615.0	1528.9
O ₂		40.5	77.6	40.7		0.6	1577.7	34.5
H ₂ O						415.7	7732.8	580.7
SO ₂						6.3	14.6	20.3
COS	5.4	4.9	4.9	0.2	5.4	0.8 [@]		
C ₂ H ₄	21.6	0.1	0.1		21.7			
C ₃ H ₆	16.5	31.6	31.6		16.5			
C ₄ H ₈	1.3	25.6	25.6		1.3			
CH ₃ OH	13.9				13.9			
S vapor						0.6		
Total	39618.6	2069.2	1679.4	570.6	39426.7	1339.4	89212.8	2394.1

[@]total organic sulfur as COS

System I(b) (continued)

Stretford Incinerator Calculations

$$\Delta H_C = 484.16 - 1.84 = 482.32 \times 10^6 \text{ BTU/hr}$$

$$\Delta H_P = (827.15 + .02x) + (6.79 + .005x) + (147.81 + .111x) + (40.77 + .033x) + 0.29 = 1022.81 + .169x$$

$$x = \frac{1022.81 - 482.32}{.206} = 2623.7 \text{ lb-mole/hr}$$

$$\begin{aligned} \text{Heat requirement} &= .375x \\ &= 983.9 \times 10^6 \text{ BTU/hr} \end{aligned}$$

$$\begin{aligned} \text{CO}_2 &= 41649 + x &= 44272.7 \\ \text{H}_2\text{O} &= 2485.4 + 2x &= 7732.8 \\ \text{O}_2 &= 528.2 + .4x &= 1577.7 \\ \text{N}_2 &= 11923 + 9.03x &= 35615.0 \\ \text{SO}_2 &= 14.6 &= 14.6 \end{aligned}$$

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Claus Incinerator Calculations (all numbers in $10^{10}/10^5$)

	ΔH_R	ΔH_C	ΔH_P	Fuel composition
CO ₂	2.94		30.48 + 0.20x	153.5 + x
H ₂ S	0.22	29.37	-	-
N ₂	10.82		104.24 + 1.12x	840.8 + 9.03x
O ₂	0.01		0.52 + 0.05x	4.02 + .4x
H ₂ O	6.98		70.25 + 0.33x	428.3 + 2x
SO ₂	0.15		3.98	20.3
COS	0.01	1.90	-	-
S	0.01	.77		
	21.14	32.04	209.47 + 1.70x	2394.1

$$x = \frac{209.47 - 32.04 - 21.14}{2.05} = 76.2 \text{ lb-mole CH}_4/\text{hr} = 28.6 \times 10^6 \text{ BTU/hr}$$

System I(c)

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Component	Stretford Feed lb-mole/hr	ADIP Feed lb-mole/hr	ADIP Vent to Incinerator lb-mole/hr	Claus Feed (Vent + ADIP) lb-mole/hr	Stretford Exhaust lb-mole/hr	Claus Exhaust lb-mole/hr	Incinerated Exhaust lb-mole/hr	Stretford Incinerator Inlet lb-mole/hr	Incinerated Stretford lb-mole/hr
CH ₄	273.4				273.4			273.4	-
C ₂ H ₆	142.0	126.5	126.5	2.8	142.0	-		268.5	-
C ₃ H ₈	24.3	55.5	55.5	-	24.3	-		79.8	-
C ₄ H ₁₀	2.4	28.2	28.2	-	2.4	-		30.6	-
CO ₂	38784.2	1393.4	1329.0	147.7	38784.2	152.2	351.2	40113.2	44268.4
CO	44.1		-	-	44.1	-		44.1	-
H ₂	93.7		-	-	93.7	-		93.7	-
H ₂ S	587.4	1088.7	0.4	1137.2	3.9	37.9		4.3	-
N ₂			-	-		2175.8	4225.0	-	35506.8
O ₂			-	-		1.5	90.8	-	1572.9
H ₂ O		40.5	77.6	40.7		1142.8	1574.5	77.6	7683.0
SO ₂				-		19.0 ^a	60.6	-	35.2
COS	16.2	14.7	14.7	0.6	16.2	2.1		30.9	-
C ₂ H ₄	21.6	0.1	0.1	-	21.6			21.7	-
C ₃ H ₆	16.5	31.6	31.6	-	16.5			48.1	-
C ₄ H ₈	1.3	25.6	25.6	-	1.3			26.9	-
CH ₃ OH	13.9				13.9			13.9	-
S vapor						1.6			
Total	40021.0	2804.8	1689.2	1325.8	39437.5	3531.3	6302.1	41126.7	89066.3

^a total organic sulfur as COS

System I(c) (continued)

Stretford Incinerator Calculations

$$\Delta H_C = 484.16 - .02 - 1.72 + 7.36 = 489.78 \times 10^6 \text{ BTU/hr}$$

$$\Delta H_P = (827.56 + .02x) + (149.26 + .11x) + (6.85 + .05x) + (40.77 + .33x) + .69 = 1025.13 \times 10^6 \text{ BTU/hr}$$

$$\begin{aligned} CO_2 &= 41669.6 + x = 44268.4 \\ H_2O &= 2485.4 + 2x = 7683.0 \\ O_2 &= 533.4 + 0.4x = 1572.9 \\ N_2 &= 12039.6 + 9.03x = 35506.8 \\ SO_2 &= 35.2 = 35.2 \end{aligned}$$

Claus Incinerator Calculations

	ΔH_R	ΔH_C	ΔH_P	Fuel composition
CO ₂	2.93		30.64 + 0.20x	154.3 + x
H ₂ S	0.66	88.34	-	-
N ₂	18.83		303.37 + 1.12x	2447.0 + 9.03x
O ₂	.02		1.55 + 0.05x	12.0 + 0.40x
H ₂ O	19.19		193.66 + .33x	1180.7 + 2x
SO ₂	0.45		11.88	60.6
CNS	.03	4.99		
S	.03	2.05		
	42.14	95.38	541.10	6302.1

$$x = \frac{541.10 - 95.38 - 42.14}{2.05} = 196.9 \text{ lb-mole } CH_4/\text{hr} = 73.8 \times 10^6 \text{ BTU/hr}$$

$$x = \frac{1025.13 - 489.78}{.206} = 2598.8 \text{ lb-mole } CH_4/\text{hr}$$

$$\text{Heat requirement} = .375x = 974.5 \times 10^6 \text{ BTU/hr}$$

System II (1)(a)

Component	Stretford Feed lb-mole/hr	Stretford Outlet lb-mole/hr	ΔH_C BTU x 10^6 /hr	$\dot{m}$ out lb-mole/hr	ΔH_P BTU x 10^6 /hr	Incinerator Outlet lb-mole/hr
CH ₄	273.4	273.4	94.36	-	-	
C ₂ H ₆	271.3	271.3	166.66	-	-	
C ₃ H ₈	79.8	79.8	76.22	-	-	
C ₄ H ₁₀	30.6	30.6	37.88	-	-	
CO ₂	40621.6	40621.6		42155.7 + x	837.21 + .020x	44826.2
CO	44.1	44.1	5.37	-	-	
H ₂	93.7	93.7	9.75	-	-	
H ₂ S	166.4	4.2	0.98	-	-	
N ₂	-	-		11907.6 + 9.03x	147.62 + 111x	36022.2
O ₂	-	-		527.6 + 0.4x	6.78 + .005x	1595.8
H ₂ O	68.2	68.2		2484.3 + 3.2x	40.75 + .033	7825.3
SO ₂		-		7.2	0.14	7.2
COS	3.0	3.0	0.71	-	-	
C ₂ H ₄	21.7	21.7	12.35	-	-	
C ₃ H ₆	48.1	48.1	42.60	-	-	
C ₄ H ₈	26.9	26.9	31.45	-	-	
CH ₃ OH	13.9	13.9	4.04	-	-	
Total	41754.4	41600.4	482.37		1032.50 + .169x	90276.7

System II (1)(a) (continued)

$$\begin{aligned} \text{CO}_2 \text{ out} &= \text{CH}_4 + 2 \text{C}_2\text{H}_6 + 3 \text{C}_3\text{H}_8 + 4 \text{C}_4\text{H}_{10} + \text{CO}_2 + \text{CO} + \text{COS} + 2 \text{C}_2\text{H}_4 + 3 \text{C}_3\text{H}_6 + \\ &\quad 4 \text{C}_4\text{H}_8 + \text{CH}_3\text{OH} + x \\ &= 42155.7 + x \end{aligned}$$

$$\begin{aligned} \text{H}_2\text{O out} &= 2 \text{CH}_4 + 3 \text{C}_2\text{H}_6 + 4 \text{C}_3\text{H}_8 + 5 \text{C}_4\text{H}_{10} + \text{H}_2 + \text{H}_2\text{S} + \text{H}_2\text{O} + 2 \text{C}_2\text{H}_4 + 3 \text{C}_3\text{H}_6 + \\ &\quad 4 \text{C}_4\text{H}_8 + 2 \text{CH}_3\text{OH} + 2x \\ &= 2484.3 + 2x \end{aligned}$$

$$\begin{aligned} \text{O}_2 \text{ out} &= 1.2 \left[\frac{1}{2} (44.1) + \frac{1}{2} (93.7) + 2(273.4) + 3(21.7) + \frac{7}{2} (271.3) + \right. \\ &\quad \left. 5(79.8) + \frac{13}{2} (30.6) + \frac{9}{2} (48.1) + 6(26.9) + \frac{3}{2} (13.9) + \right. \\ &\quad \left. \frac{3}{2} (7.2) + 2x \right] \\ &= .2/1.2 (3165.3 + 2.4x) = 527.6 + 0.4x \end{aligned}$$

$$\begin{aligned} \text{O}_2 \text{ required} &= 1.2 [22.05 + 46.85 + 546.8 + 65.1 + 949.55 + 399 + 198.9 + \\ &\quad 216.45 + 161.4 + 20.85 + 10.65 + 2x] \end{aligned}$$

$$\text{N}_2 = 79/21 [\text{O}_2] = 11907.6 + 9.03x$$

$$.375x = 1032.50 + .169x - 482.37$$

$$x = \frac{550.13}{.206} = 2670.5 \text{ lb-moles CH}_4/\text{hr}$$

$$\text{Heat required} = 1001.4 \times 10^6 \text{ BTU/hr}$$

System II (1)(b)

Component	Stretford Feed lb-mole/hr	Stretford Outlet lb-mole/hr	ΔH_C BTU x 10^6 /hr	$\dot{m}$ out lb-mole/hr	ΔH_p BTU x 10^6 /hr	Incinerator Outlet lb-mole/hr
CH ₄	273.4	273.4	94.36	-		
C ₂ H ₆	271.3	271.3	166.66	-		
C ₃ H ₈	79.8	79.8	76.22	-		
C ₄ H ₁₀	30.6	30.6	37.88	-		
CO ₂	40621.6	40621.6		42163.2 + x	837.36 + .020x	44829.7
CO	44.1	44.1	5.37	-		
H ₂	93.7	93.7	9.75	-		
H ₂ S	574.4	4.2	0.98	-		
N ₂	-	-		11958.4 + 9.03x	148.25 + .111x	36036.9
O ₂	-	-		529.9 + 0.4x	6.81 + .005x	1596.5
H ₂ O	68.2	68.2		2484.3 + 2x	40.75 + .033x	7817.3
SO ₂	-	-		14.7	0.29	14.7
COS	10.5	10.5	2.50	-		
C ₂ H ₄	21.7	21.7	12.35	-		
C ₃ H ₆	48.1	48.1	42.60	-		
C ₄ H ₈	26.9	26.9	31.45	-		
CH ₃ OH	13.9	13.9	4.04			
	42026.6	41606.2	484.16		1033.46 + .169x	90295.1

$$.375x = 1033.46 + .169x - 484.16$$

$$x = \frac{549.30}{.206} = 2666.5 \text{ lb-moles CH}_4/\text{hr}$$

$$\text{Heat requirement} = 999.94 \times 10^6 \text{ BTU/hr}$$

System II (1)(c)

Component	Stretford Inlet lb-mole/hr	Stretford Outlet lb-mole/hr	ΔH_c BTU x 10^6 /hr	$\dot{m}$ out lb-mole/hr	ΔH_p BTU x 10^6 /hr	Incinerator Outlet lb-mole/hr
CH ₄	273.4	273.4	94.36			
C ₂ H ₆	271.3	271.3	166.66			
C ₃ H ₈	79.8	79.8	76.22			
C ₄ H ₁₀	30.6	30.6	37.88			
CO ₂	40621.6	40621.6		42184.2 + x	837.78 + .020x	44839.4
CO	44.1	44.1	5.37			
H ₂	93.7	93.7	9.75			
H ₂ S	1723.2	4.2	0.98			
N ₂	-	-		12100.6 + 9.03x	150.01 + .111x	36077.1
O ₂	-	-		536.2 + 0.4x	6.89 + .005x	1598.3
H ₂ O	68.2	68.2		2484.3 + 2x	40.25 + .033x	7794.7
SO ₂	-	-		35.7	.70	35.7
COS	31.5	31.5	7.50			
C ₂ H ₄	21.7	21.7	12.35			
C ₃ H ₆	48.1	48.1	42.60			
C ₄ H ₈	26.9	26.9	31.45			
CH ₃ OH	13.9	13.9	4.04			
	43346.2	41627.2	489.16		1036.13 + .169x	90345.2

$$.375x = 1036.13 + .169x - 489.16$$

$$x = \frac{546.97}{.206} = 2655.2$$

$$\text{Heat required} = 995.70 \times 10^6 \text{ BTU/hr}$$

Systems II (2) (a), (b), and (c)

Add SO₂ scrubbing to Claus incinerator exhausts in
systems I (a), (b), and (c) as follows:

Component	System II (2)(a)		System II (2)(b)		System II (2)(c)	
	Claus Exhaust lb-mole/hr	SO ₂ Scrubber Exhaust lb-mole/hr	Claus Exhaust lb-mole/hr	SO ₂ Scrubber Exhaust lb-mole/hr	Claus Exhaust lb-mole/hr	SO ₂ Scrubber Exhaust lb-mole/hr
CO ₂	190.5	190.5	229.7	229.7	351.2	351.2
N ₂	608.5	608.5	1528.9	1528.9	4225.0	4225.0
O ₂	16.1	16.1	34.5	34.5	90.8	90.8
H ₂ O	232.7	232.7	580.7	580.7	1574.5	1574.5
SO ₂	<u>7.3</u>	<u>0.3</u>	<u>20.3</u>	<u>0.6</u>	<u>60.6</u>	<u>1.6</u>
Total	1055.1	1048.1	2394.1	2394.4	6302.1	6243.1

APPENDIX C-III

ENERGY IMPACT OF ALTERNATIVE EMISSION CONTROL SYSTEMS

ENERGY CALCULATIONS

To determine the energy impact of alternate control systems, the following assumptions were made:

- a. All steam is generated on-site by coal-fired boilers at 80 percent efficiency;
- b. All electricity is generated on-site by coal-fired boilers at 34.13 percent efficiency;
- c. Incineration fuel is product SNG made at 64.51 percent thermal efficiency; and
- d. Waste heat recovery in incinerators is based on 70 percent fuel heat recovery at a combustion temperature of 1600°F:
 - (i) steam generation is 61.6 percent of fuel heat input
 - (ii) preheated inlet gases are 8.4 percent of fuel heat input

Thus the energy impact of alternate emission controls may be determined by calculating the additional coal required to generate the amounts of steam, electricity, and SNG consumed by each control system. These calculations assume the following conversion factors:

$$1 \text{ Kilowatt-hour electricity} = \frac{3413 \text{ Btu}}{.3413} \text{ or } 10,000 \text{ Btu of coal}$$

$$1 \text{ pound steam} = \frac{1000 \text{ Btu}}{.80} \text{ or } 1250 \text{ Btu of coal}$$

$$1000 \text{ Btu of SNG} = \frac{1000 \text{ Btu}}{.6451} \text{ or } 1550 \text{ Btu of coal}$$

To simplify the impact of incineration based on assumptions (c) and (d) above, the following case was investigated. Assuming X number of Btu's were required to incinerate a given gas stream, then $X/.6451$ Btu's of coal would be fed to the gasifiers. But 8.4 percent of incineration fuel is recovered as preheat air; thus, the coal to gasifier rate is diminished by that amount. Coal to gasifier is then $X \left(\frac{.916}{.6451} \right)$.

Sixty-one and six-tenths percent of the incinerator fuel is recovered as steam, which diminishes the coal requirements of the main boiler by $.616X$. The net energy cost for incineration is thus:

$$-.80$$

$$X \left[\frac{(.916)}{.6451} - \frac{(.616)}{.80} \right] \text{ OR } 0.65X,$$

where X is the theoretical SNG heat required to incinerate any control system off-gases.

The utilities consumption for specific control processes are as follows:

Stretford Steam = 1473 lb per long ton sulfur recovered

Stretford Electricity = 1353 KWH per long ton sulfur recovered

ADIP Steam: 60# consumed = 4.6 lb/lb H_2S removed

ADIP Electricity = .006 KW/lb H_2S removed

Claus Steam: 60# generated = 10,800 lb per long ton sulfur recovered
600# consumed = 960 lb per long ton sulfur recovered

Claus Electricity = 36 KWH per long ton feed sulfur

Wellman-Lord Electricity = 1120 KWH per long ton sulfur recovered

Wellman-Lord Steam: 15# consumed = 600 lb per lb-mole sulfur recovered

ENERGY REQUIREMENTS
(All Figures in 10^6 Btu/Day)

System I (a)

Stretford Steam = (1473)(19.31)(1250) =	35.55
Stretford Electricity = (1353)(19.31)(19000) =	261.26
ADIP Steam = (4.6)(85477.7)(1250) =	491.50
ADIP Electricity = (.006)(85477.7)(10000) =	5.13
Claus Steam Used = (960)(35.11)(1250) =	42.13
Claus Steam Credit = (10800)(35.11)(1250) =	(473.99)
Claus Electricity = (36)(37.62)(10000) =	13.54
Claus Incineration = (.65)(13.9 x 10^6)(24) =	216.84
Stretford Incineration = (.65)(981.8 x 10^6)(24) =	<u>15312.96</u>
TOTAL:	15904.92

System I (b)

Stretford Steam = (1473)(65.93)(1250) =	121.39
Stretford Electricity = (1353)(65.93)(10000) =	892.03
ADIP Steam Used = (4.6)(296513.4091250) =	1704.95
ADIP Electricity Used = (.006)(296513.4)(10000) =	17.79
Claus Steam Used = (960)(121.10)(1250) =	145.32
Claus Steam Credit = (10800)(121.10)(1250) =	(1634.85)
Claus Electricity = (36)(130.34)(10000) =	46.92
Claus Incineration = (.65)(28.60 x 10^6)(24) =	446.16
Stretford Incineration = (.65)(983.9 x 10^6)(24) =	<u>15348.84</u>
TOTAL:	17088.55

System I (c)

Stretford Steam = (1473)(200.47)(1250) =	369.12
Stretford Electricity = (1353)(200.47)(10000) =	2712.36
ADIP Steam Used = (4.6)(890194.6)(1250) =	5118.62
ADIP Electricity Used = (.006)(890194.6)(10000) =	53.41
Claus Steam Used = (960)(370.1)(1250) =	444.12
Claus Steam Credit = (10800)(370.1)(1250) =	(4996.35)
Claus Electricity = (36)(390.9)(10000) =	140.72
Claus Incineration = (.65)(73.8)(24) =	1151.28
Stretford Incineration = (.65)(974.5)(24) =	<u>15202.20</u>
TOTAL:	20195.48

System II (1)(a)

Stretford Steam = $(1473)(55.73)(1250) = 102.61$
 Stretford Electricity = $(1353)(55.73)(10000) = 754.03$
 Stretford Incineration = $.65(1001.40 \times 10^6)(24) = 15621.84$
 TOTAL: 16478.48

System II (1)(b)

Stretford Steam = $(1473)(195.90)(1250) = 360.70$
 Stretford Electricity = $(1353)(195.90)(10000) = 2650.53$
 Stretford Incineration = $.65(999.94)(24) = 15599.06$
 TOTAL: 18610.29

System II (1)(c)

Stretford Steam = $(1473)(590.59)(1250) = 1087.42$
 Stretford Electricity = $(1353)(590.59)(10000) = 7990.68$
 Stretford Incineration = $.65(995.70)(24) = 15532.92$
 TOTAL: 24611.02

System II (2)(a)

Energy for System I (a) = 15904.92
 Wellman-Lord Electricity = $(1120)(2.40)(10000) = 26.88$
 Wellman-Lord Steam Consumed = $600(7.0)(24)(1250) = 126.00$
 TOTAL: 16057.80

System II (2)(b)

Energy for System I (b) = 17088.55
 Wellman-Lord Electricity = $(1120)(6.77)(10000) = 75.82$
 Wellman-Lord Steam Consumed = $600(19.7)(24)(1250) = 354.60$
 TOTAL: 17518.97

System II (2)(c)

Energy for System I (c) = 20195.48
 Wellman-Lord Electricity = $(1120)(20.27)(10000) = 227.02$
 Wellman-Lord Steam Consumed = $600(59.0)(24)(1250) = 1062.00$
 TOTAL: 21484.50

LIQUID AND SOLID WASTES

BASES:

Stretford Purge: 10 gal/100 lb-mole feed gas
Wellman-Lord Purge: 15 gal/lb-mole S recovered
Acid Condensate: 21 gal/lb-mole S recovered
Claus Catalyst: 0.33 lb Al_2O_3 LT sulfur removed

System I (a)

Stretford Purge = $(39475.7)(0.1)(24) = 94742$ gal/day
Claus Catalyst = $(0.33)(35.11) = 11.5$ lb/day

System I (b)

Stretford Purge = $(39618.6)(0.1)(240) = 95085$ gal/day
Claus Catalyst = $(0.33)(123.3) = 40.7$ lb/day

System I (c)

Stretford Purge = $(40021.0)(0.1)(24) = 96050$ gal/day
Claus Catalyst = $(0.33)(369.88) = 122.1$ lb/day

System II (1)(a)

Stretford Purge = $(41574.4)(0.1)(24) = 99778$ gal/day

System II (1)(b)

Stretford Purge = $(42076.6)(0.1)(24) = 100984$ gal/day

System II (1)(c)

Stretford Purge = $(43346.6)(0.1)(24) = 104031$ gal/day

System II (2)(a)

Stretford Purge = $(41574.4)(0.1)(24) = 99778$ gal/day
Claus Catalyst = $(0.33)(35.11) = 11.5$ lb/day
Wellman-Lord Purge = $15(7)(24) = 2520$ gal/day
Acid Condensate = $21(7)(24) = 3528$ gal/day

System II (2)(b)

Stretford Purge = $(39618.6)(0.1)(24) = 95085$ gal/day
Claus Catalyst = $(0.33)(123.3) = 40.7$ lb/day
Wellman-Lord Purge = $15(19.7)(24) = 7092$ gal/day
Acid Condensate = $21(19.7)(24) = 9929$ gal/day

System II (2)(c)

Stretford Purge = $40021(0.1)(24) = 96050$ gal/day

Claus Catalyst = $(0.33)(369.88) = 122.1$ lb/day

Wellman-Lord Purge = $15(59)(24) = 21240$ gal/day

Acid Condensate = $21(59)(24) = 29736$ gal/day

APPENDIX C-IV
AMBIENT AIR QUALITY IMPACT OF
ALTERNATIVE EMISSION CONTROL SYSTEMS

Appendix C-IV

Ambient Air Quality Impact Analysis

The potential ambient air quality impact of both an uncontrolled and a controlled Lurgi coal gasification plant producing 250 billion Btu per day of SNG was assessed using a mathematical air quality dispersion model. This model, referred to as the Single Source (CRSTER) Model, is a state-of-the-art Gaussian plume model employing the basic concepts described by Turner.¹ The model simulates the interaction between emissions from a point source and meteorological conditions to predict ambient air pollutant concentrations for each hour at 180 receptors placed at preselected locations around the source. These one-hour concentrations are then used to determine ambient air pollutant concentrations for longer time periods.

Meteorological conditions chosen for use in this assessment approximate those occurring in eastern Wyoming. Eastern Wyoming is an area reasonably representative of those areas where Lurgi SNG coal gasification plants might be located. The terrain is rolling which often influences local channeling of wind flows, while general weather features tend to enhance strong nighttime inversions. To simulate these conditions in a flat terrain model, actual observations from this area would be desirable. Meteorological data from a weather station in Rapid City, North Dakota, provide upper air soundings representative of mixing heights in eastern Wyoming. Surface meteorological data at Rapid City, however, is too heavily influenced by mountain effects to be considered representative of eastern Wyoming. The same is true for the next closest weather station, located in Casper, Wyoming. Denver, Colorado, on the other hand, while subject to channeled wind regimes, is not totally dominated by them. Hence, of the

available meteorological data, surface data from Denver and upper air soundings from Rapid City are considered the best approximation of eastern Wyoming meteorological conditions.

In flat-to-gently rolling terrain, such as that assumed in this analysis, experience indicates that the Single Source (CRSTER) Model estimates are reliable to within a factor of two. Direct extrapolation of the results obtained in this study to actual plants, however, should not be attempted. Such extrapolation could lead to erroneous conclusions, since plants may vary considerably in their characteristics and in their location with respect to large and small-scale meteorological features. The air quality impact of actual plants should only be considered on a case-by-case basis.

Table C-IV.1 summarizes the emission source parameters used in this analysis to characterize a Lurgi SNG coal gasification plant. The various coal sulfur levels are denoted by subcases a, b, and c as defined in Appendix C-II. The only difference between cases c and c¹ is stack height. Case c¹ includes a 500-foot stack whereas case c (and cases a and b) include a 250-foot stack. The alternative emission control systems are those identified in chapter 5.

One apparent inconsistency in Table C-IV.1 that should be explained is the two different stack gas temperatures. This analysis assumes that all the waste gas streams, including that discharged by the power plant located at the site, are blended together and released to the atmosphere from a common stack. Since the mass of effluent discharged from the power plant is much greater than that discharged from the other emission sources, its temperature determines the temperature of the stack gas discharged into the atmosphere. In case a the coal sulfur content is low enough to comply with the NSPS for steam generators without the use of tail gas scrubbing.

Table C-IV.1
EMISSION SOURCE CHARACTERISTICS

Emission Control System	Stack Parameters				Emission Rate (gm/sec)				
	Temperature (°K)	Height (m)	Exit Velocity (m/s)	Diameter (m)	SO ₂	CO ₂	H ₂ S	C ₂ ⁺	CO
Uncontrolled	450	↑ 76	↑ 26	↑ 6.5	385	25	765	↑ 735	↑ 195
	↑ 320	↓	↓	↓	605	55	1730	↓	↓
	↓	152	↓	↓	605	225	7320	↓	↓
	↓	↓	↓	↓	605	225	7320	↓	↓
Alternative I	450	↑ 76	↑ 26	↑ 7.5	500	↑ 3	↑ <1	↑ 15	↑ 15
	↑ 320	↓	↓	↓	885	↓	↓	↓	↓
	↓	152	↓	↓	1375	↓	↓	↓	↓
	↓	↓	↓	↓	1375	↓	↓	↓	↓
Alternative III	450	↑ 76	↑ 26	↑ 7.5	445	↑ 3	↑ <1	↑ 15	↑ 15
	↑ 320	↓	↓	↓	725	↓	↓	↓	↓
	↓	152	↓	↓	900	↓	↓	↓	↓
	↓	↓	↓	↓	900	↓	↓	↓	↓

In cases b and c, however, tail gas scrubbing is necessary on the power plant to comply with the NSPS and, as a result, the stack gas temperature is lower.

The results of this analysis are summarized in Table C-IV.2. Although an uncontrolled Lurgi SNG coal gasification plant would probably meet both the maximum Prevention of Significant Deterioration (PSD) increment and the National Ambient Air Quality Standard (NAAQS) for SO_2 , it appears that such a plant would probably violate both the NAAQS for non-methane hydrocarbons and carbon monoxide. It is also quite obvious from the resulting high ambient air concentrations of H_2S is $45 \mu\text{g}/\text{m}^3$), that injury to certain crops such as alfalfa, barley and cotton would occur, and that in the worst cases individuals in the area would experience eye irritation.

Under alternative emission control system I, a Lurgi SNG coal gasification plant would comply with the NAAQS for SO_2 , CO, and non-methane hydrocarbons. No odor problem would probably exist. While a plant gasifying low or moderate sulfur coal would likely comply with the maximum PSD increment for SO_2 , it is equally unlikely that a plant gasifying high sulfur coal would comply with this requirement.

Under alternative emission control system II, the situation is similar. Emissions of SO_2 are somewhat lower, however, and the likelihood of a Lurgi SNG coal gasification plant gasifying high sulfur coal and meeting the PSD increment for SO_2 is improved.

Table C-IV.2

AMBIENT AIR QUALITY IMPACT

Maximum Ambient Air Concentrations

Emission Control System	SO ₂			COS			H ₂ S			C ₂ ⁺		CO	
	3-hr	24-hr	Annual	1-hr	24-hr	Annual	1-hr	24-hr	Annual	3-hr	1-hr	1-hr	8-hr
Uncontrolled													
a	90	10	<1	15	<1		535	25	1	170	135	20	
b	335	40	2	90	5		2875	120	5	410	320	45	
c	335	40	2	380	15		12,160	510	30	410	320	45	
c1	310	40	2	350	15		11,200	475	15	380	300	40	
Alternative I													
a	100	15	<1	2	<1		<1	<1	<1	3	10	1	
b	455	70	3	4	<1		<1	<1	<1	5	20	3	
c	705	110	5	4	<1		<1	<1	<1	5	20	3	
c1	590	80	4	4	<1		<1	<1	<1	5	15	3	
Alternative II													
a	90	10	<1	2	<1		<1	<1	<1	3	10	1	
b	425	65	3	4	<1		<1	<1	<1	5	20	3	
c	460	70	4	4	<1		<1	<1	<1	5	20	3	
c1	385	50	2	4	<1		<1	<1	<1	5	15	3	
PSD Increment	512	91	20	-	-		-	-	-	-	-	-	
NAAQS	-	365	80	-	-		-	-	-	160	40	10	

APPENDIX C-V. DERIVATION OF EQUATION FOR SULFUR
EMISSIONS FROM GASIFICATION OF COAL

From Table 5.2 the following engineering estimates for sulfur emissions from the control systems under consideration are:

System I - Low sulfur	.072 lb/lb sulfur input
Medium sulfur	.058 lb/lb sulfur input
High sulfur	.053 lb/lb sulfur input
System II - Low sulfur	.036 lb/lb sulfur input
Medium sulfur	.024 lb/lb sulfur input
High sulfur	.020 lb/lb sulfur input

These emissions were based upon engineering data furnished by operators of proposed Lurgi gasification plants, in which a H_2S /organic sulfur ratio of 98.2/1.8 in Rectisol acid gases was shown. Calculations were shown in Appendix C-II

Figure C-5.1 shows these numbers plotted as a function of the coal feedstock sulfur/higher heating value ratio, which were 0.4, 1.2, and 3.6 lb sulfur per million Btu ($lb/10^6$ Btu) for low, medium, and high sulfur cases, respectively.

However, it is not certain that organic sulfur will constitute only 1.8 percent of the sulfur in the gas stream leaving shift conversion as the above equation assumes. Some factor (F), which would vary as the organic sulfur component of the shifted gas stream, is needed in this equation.

Thus, the equation would be:

$$E = 0.03 F (A)^{.75} (B)^{.25}$$

Where:

E = Allowable sulfur emissions in lb/hr.

A = Sulfur in coal feed in lb/hr.

B = Higher heating value of coal feed in 10^6 Btu/hr.

The equation corresponding to an organic sulfur level of 4.0 percent is:

$$E = 0.05 (A)^{.75} (B)^{.25}$$

If it is assumed that "E" varies linearly between an organic sulfur concentration of 1.8 and 4.0 percent, an equation for "F" can be found. Using $E = 0.03 F (A)^{.75} (B)^{.25}$ as the basic equation, F should be 1 for an organic sulfur concentration of 1.8 percent. F should be 1.66 for an organic sulfur concentration of 4.0 percent so as to generate

$E = 0.05 (A)^{.75} (B)^{.25}$. This procedure results in two points which can be plotted to give the F equation, as illustrated below:

<u>Percent Organic Sulfur vs. F</u>		
Factor (F)	1	1.66*
COS %	1.8	4

The equation resulting from plotting these points is:

$$F = 0.3 (\% \text{ organic sulfur}) + 0.46$$

Thus sulfur emissions are limited by:

$$E = 0.03 F (A) ^{.75} (B) ^{.25}$$

Where:

$$F = 0.3 (\% \text{ organic sulfur}) + 0.46$$

and "% organic sulfur" is the percent of the total sulfur in the gas stream from shift conversion which is present as organic sulfur.

*At COS = 1.8 percent, E = 0.03, at COS = 4.0 percent, E = 0.05

If E = 0.03 F... is basic equation, then where COS = 4 percent .03 F = 0.05;

thus $F = \frac{.05}{.03} = 1.66$ for COS = 4 percent.